BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matter of:	)	
	)	Docket No. 09-IEP-10
Preparation of the 2009	)	
Integrated Energy Policy	)	
Report (2009 IEPR)	)	

COMMITTEE WORKSHOP ON INTER-AGENCY ANALYSIS OF GENERATION AND TRANSMISSION OPTIONS FOR ELIMINATING RELIANCE UPON ONCE-THROUGH COOLING POWER PLANTS

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JULY 28, 2009

9:30 A.M.

Reported by:
Peter Petty

COMMISSIONERS PRESENT

Jeffrey D. Byron, Presiding Member,
IEPR Committee
Laurie ten Hope, His Advisor

James D. Boyd, Vice Chair and Associate Member,
IEPR Committee
Kelly Birkinshaw, His Advisor

STAFF PRESENT

Suzanne Korosec, IEPR Lead

Michael Jaske

David Vidaver

Eileen Allen

Mark Hesters

ALSO PRESENT

At Dais

John Bohn, Commissioner, California Public Utilities Commission (CPUC)
Steve St. Marie, His Advisor

Yakout Mansour, California Independent System Operator (CAISO)

CPUC Staff

Robert Strauss

Simon Baker

CAISO Staff

Dennis Peters

Presenters

Pedro Pizarro, Southern California Edison (SCE)

Also Present (Cont.) (via WebEx)

Panelists

Alan Comnes, NRG Energy

Matthew Barmack, Calpine

Don Vawter, AES

Vafa Mohtashami, RRI Energy

Doug Davie, Wellhead

Will Mitchell, CPV

Dale Fredericks, DG Power

Rob Anderson, San Diego Gas & Electric (SDG&E)

Kevin Cini, SCE

Marino Monardi, Pacific Gas & Electric (PG&E)

Matthew Tisdale, CPUC/DRA (Department of Ratepayer Advocates)

Mike Florio, TURN

V. John White, CEERT

Hamid Nejad, Los Angeles Department of Water & Power (LADWP)

Mohsen Nazemi, South Coast Air Quality Management District

Suzanne Phinney: League of Women Voters of California

David Pettit: Natural Resources Defense Council (NRDC)

Jeff Harris: Ellison Schneider & Harris, LLP

Laura Manz, CAISO

Pat Arons, SCE

Also Present (Cont.)

Mark Esguerra, PG&E

Mohammed Beshir, LADWP

Public

David Nelson, Coastal Alliance on Plant Extension (CAPE)

Joe Geever, Surfrider Foundation

Steven Kelly, Independent Energy Producers (IEP)

Rob Simpson, Californians for Renewable Energy (CARE)

Mark Krausse, Pacific Gas & Electric (PG&E)

Angela Haren, California Coastkeeper Alliance

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P R O C E E D I N G S

JULY 28, 2009 9:32 A.M.

Agenda Item 1: Introductions and Announcements - Agenda Review

MS. KOROSEC: Good morning. I am Suzanne Korosec. I lead the unit that produces the Energy Commission's Integrated Energy Policy Report, or IEPR. Welcome to today's IEPR Committee Workshop on Generation and Transmission Options for Eliminating Reliance on Once-Through Cooling Power Plants.

Just a few housekeeping items before we get started. The restrooms are out in the atrium through the double-doors and to your left, there is a snack room on the second floor of the atrium at the top of the stairs, under the white awning, and if there is an emergency and we need to evacuate the building, please follow the staff across the street to the park, where we will wait for the all clear signal.

Today's workshop is being broadcast through our WebEx Conferencing System, so parties need to be aware that we are recording the workshop. The recording will be available on our website immediately after the workshop, and then we will post the written transcript when that becomes available, which just takes about two weeks.

For presenters and commenters, please make sure to speak directly into the microphone so that the WebEx folks can hear you speak and so that we can accurately capture it on the transcript.

During the Q&A and public comment periods today, we will hear first from the folks in the room, and then we will hear from the WebEx participants. For those of you who are listening in on WebEx, if you want to ask a question, please send the question to our coordinator, using the chat function, and we will make sure that gets passed on to the presenters and panelists. During the public comment period at the end of the day, we will open the lines for anybody who wishes to speak out there on the line.

When you do come up to speak, those of you in the room, it is very helpful if you can give the Court Reporter your business card, so that we can make sure that your name and affiliation are reflected accurately. We are also asking parties to submit written comments and those are due by 5:00 p.m. on August 11th.

So the purpose of today's workshop is to discuss and get public comment on a proposal by the Energy Commission, the Public Utilities Commission, and the California Independent System Operator to address the reliability impacts of the State Water Resources Control Board's efforts to develop a policy to mitigate the biological impacts of using ocean water in power plant cooling. Just as an aside, I want to reiterate the statement that was in the notice of today's workshop, that the energy agencies fully support the Water Board's Long-Term goal of eliminating once-through cooling, and this workshop is not the forum to debate that goal. Today's focus is electricity reliability.

Since the IEPR was first published in 2003, the Energy Commission has continued to raise concerns about reliability impacts of the state's fleet of aging power plants. In the 2004 IEPR Update, the Energy Commission identified a group of older power plants for a detailed study of the role that they played in maintaining reserve margins and providing reliability services. The 2005 IEPR continued this discussion, and followed it up with a specific policy recommendation that utility procurement plans should provide for the orderly retirement, or re-powering by 2012, of the aging power plants that were identified in the 2004 IEPR Study. This recommendation was also repeated in the 2007 IEPR.

The Energy Commission has also spent a lot of time studying the biological impacts of once-through cooling and its implications on power plants, and many of our studies were referenced in the Water Board's Draft Substitute Environmental Document that was released earlier this month. The need for new power plants to either partly, or completely replace once-through cooling power plants is of particular concern in Southern California because of that region's vulnerability to supply shortages. However, there is a limited supply of offsets or emissions credits in the South Coast Air Quality Management District, which will make it difficult to license new power plants in Southern California. The Energy Commission issued a paper on this topic in February 2009 that discussed these conflicts between providing reliable power and protecting the environment.

In the fall of 2008, the Energy Commission, PUC, and CAISO began working together to develop a Joint Proposal to the State Water Resources Control Board on how to assure electric grid reliability while reducing once-through cooling in existing power plants. In May of this year, the IEPR Committee held a workshop to get input from stakeholders on the reliability issues associated with once-through cooling mitigation. After the workshop, the energy agencies finalized their proposal, gave it to the Water Board, who has incorporated it into that Draft Substitute Environmental document that was released July 15th.

So today's workshop is focusing on how to implement the Joint Agencies' proposal. While this workshop is part of the 2009 IEPR Proceeding, it is also being jointly sponsored by the CPUC as part of their 2008 Long-Term Procurement Plan Rulemaking, given the prominent role the PUC has in providing procurement guidance to the investor-owned utilities.

Our agenda today is as follows. We will begin with opening comments from the energy agency representatives; next, Dr. Mike Jaske, the Energy Commission staff, will give a presentation on the energy agencies' proposal, followed by a brief Q&A. We will then have our first panel, which will discuss changes needed in investor-owned utility and procurement practices from the point of view of generators, developers, and bidders. After the panel, we will take a lunch break, and then resume with the second panel on procurement changes needed from the load serving entity, investor-owned utility, and consumer points of view. Next, we will have a panel to discuss changes that may be needed in the power plant licensing process, followed by a short break, and then we will resume with our final panel on changes that will be needed to CAISO and other balancing authority transmission processes. We will then hear public comments on the proposal and on the various panel discussions, and we will conclude with a wrap-up of the day's discussion and review of action items and next steps.

So with that, Commissioners, I will turn it over to you for opening remarks.

Agenda Item 2: Opening Comments From Agency Representatives

COMMISSIONER BYRON: Thanks, Ms. Korosec. Good morning, everyone. My name is Jeff Byron and I am the Presiding Member of the Integrated Energy Policy Report Committee. My Associate Member to my right is Commissioner -- I should say Vice Chairman Boyd of this Commission. And I am just going to go ahead and finish with an introduction and say a few remarks, and then hand them off to my fellow Commissioners for remarks, as well.

To my left is the present CEO of the Independent System Operator for the State of California, Yakout Mansour, to his left is Commissioner John Bohn from the Public Utilities Commission, his Advisor, Dr. Steve St. Marie, and all the way to my right is Commissioner Boyd's Advisor, Kelly Birkinstock, and my Advisor -- Birkinshaw, forgive me -- I am sorry.

MR. BIRKINSHAW: Thank you, Commissioner.

COMMISSIONER BYRON: And my Advisor, who I hope to get right, Ms. Laurie ten Hope. So I can tell by the attendance at this workshop that there is a great deal of interest in this subject, and I am glad there is. This is an extremely important subject that this Commission and the other energy agencies in the state have been tracking, much longer than the fall of last year. As Ms. Korosec indicated, the State Water Resources Control Board will be promulgating a rule on this issue, they have a Draft Mitigation Policy out, and it is my understanding that they intend to complete their rulemaking process by the end of this year. We will hear more about that later.

The three energy agencies are very engaged on this and working together, and you can tell by the attendance at today's meeting that it is a subject that we are cooperating and working closely together on, in trying to create a reliability-based approach to addressing this very complex issue. I say it is very complex because it really ties together with other issues that we are facing within the state, and we will get into that in more detail as we go on.

The goal here, I do not want anybody to forget, and that is we want to mitigate the environmental impact that once-through cooling creates; that is what we are obligated to do. How we go about doing it is extremely important so that we are able to maintain the level of reliability of the system that we expect to have throughout California, while also maybe addressing some of these other issues that we will get into, such as the prior reserve and the aging power plants that need to be retired. You all know it affects a substantial portion of the generation portfolio in this state and it is going to require the cooperation of all the affected parties and, by that, I mean the investor-owned utilities, the publicly-owned utilities, the independent power producers who own a number of these plants, regulators, and also environmental organizations will have a key role in seeing this process through.

Options that will be discussed are re-powering, new generation, new transmission, and I am sure there are others, but how we go about doing this and maintaining a level of reliability is the key, and it is not going to be easy. We are going to need a stable process that will go on for a long period of time. Dare I say that we will probably outlast the Commissioners and the present CEO that are sitting before you in their current positions? We will need something that will work and be stable and last for a long period of time. And, of course, it has got to be effective.

So I hope that gives you a characterization of what we are all about here. We are trying to get comments and feedback to the approach that we are embarking upon, look forward to also hearing, well, from all parties today. I think I will stop there and ask if my Associate Member of this Policy Report Committee would like to say anything.

VICE CHAIR BOYD: Thank you, Commissioner. I will be very brief. It just so happens last Thursday I sat on a panel in front of a lot of folks with representatives from the Water Board, the PUC, and the CAISO on this very same subject, and therefore I have done a lot of homework to catch myself up to speed on the subject, and it was a very lively and difficult discussion with industry, the environmental community, and what have you. So it is obvious from the size of the audience here that it is a meaningful discussion, and a subject to a whole lot of people. Several who have preceded me have made reference to other issues that are problems for us in California that relate to adequate supplies of electricity, such as the prior reserve in the South Coast, and of course, we are all wrestling with how to meet our responsibilities under AB 32 and address greenhouse gasses, but I just want to mention, I am looking personally, very strongly as a Commission, at a more systems integrated solution to all these problems, not just carving them up and trying to do a surgical strike on each one. We have got the prior reserve, we have got greenhouse gasses, we have got our policies on retiring old inefficient plants, we have got our strong policy support for distributed generation, be that CCHP, i.e., the use of waste heat, call it what you want, and we have talked at length, if not ad nauseam, about the role of transmission and distribution system upgrades, all of which in some cases could ease the pressure to just put iron on the ground, i.e., build power plants, and I hope we can seize this opportunity to look at all those 21st Century approaches to our problem. So this integrates with all that, it is really tough on us to try to do multiple things at once, but I think that is where we find ourselves. So I am looking forward to what we hear in this session today to contribute to that. I will apologize because, at around 10:00, I am going to slip away from these proceedings for a brief time because the Chairwoman and I have to sit down -- you may all think the budget crisis is solved and it is over, but we have to carve our soul up, still, to meet our commitments, so we are going to sit down to try to meet a deadline, to do some digging. So I will slip away and then come back as soon as that painful task is done. Thanks.

COMMISSIONER BYRON: Thank you, Commissioner Boyd. Well, to our two other agencies that are not having their budgets carved up today, Commissioner Bohn, thank you for coming from San Francisco, I appreciate your being here.

COMMISSIONER BOHN: Thank you, Commissioner. I am very pleased to be here. This is, as you have stated, and as Commissioner Boyd has said, this is an incredibly complex issue. The good news is that it has actually gotten a number of the agencies to actually sit down and work together, no mean feat in and of itself. But I think, from our perspective, we are kind of the mechanics in part of this, and that is to say, our particular interest is how we might adapt both our planning for our procurement process and our procurement process, that we work with the investor-owned utilities, and we might need to change that when additional elements may need to be involved in that, and how we integrate and make the decisions where we know alternatives of repowering or green field within load pockets, or transmission. These are each very thorny issues. There is a lot of theoretical discussion, there is a lot of philosophical difference, and indeed, there are competing philosophies and, in some cases, competing plans. But the important thing is that this all has to be done together and we are, in fact, working, I think, closely with one another. But we, as the mechanics, having to lay a number of these things out and get the process to work, are particularly interested in the views of those of you out here who are going to present today, and others, as to how we might, to the extent possible, simplify the process of procurement such that it accommodates these new demands. It is by no means a foregone conclusion that this can be done without a lot of acrimony. My sense is that they are very strong views and from a number of different sources on how this can best be done. But we passed the stage when we have decided to do it, and so now I hope that we will all join together and figure out how to deal with the mechanics such that we give adequate consideration to the very -- what I consider the first concern, which is reliability, and then begin to talk through in a spirit of cooperation toward the direction and the goal of integrating the various bits and pieces of this puzzle in and around a new system. So thank you for including us.

COMMISSIONER BYRON: Thank you. Mr. Mansour.

MR. MANSOUR: Thank you, Commissioner. It is really good to be here. And I echo Commissioner Bohn's statement that we should take pride of the fact that all the agencies and ISO sat together, each knowing what their responsibility is and what their role is, in part. None of us have the entire portfolio of roles, but in combination we do have it all in our hands, and we must make sure that it is done right and public policies are implemented in the proper way. The ISO is not expert in marine life and we do not determine as an entity whether rates are just and reasonable, but other Commissions, both at the state and the federal level, determine that the cost and rates are just and reasonable. We inform the policies, but our responsibility primarily is the reliability of the grid. And may I remind everyone that there are some symptoms that we all recall from the crisis time, was that one of the first symptoms was, when lights go off and on, nothing else mattered and people hammered those who were responsible for the shortage. So we want to make sure that public policies are implemented and we are committed to it, but we will always be strong and take the view that lights go on, go off, and we have enough supply to support the state economy. In that respect, first of all, I would like to really up front thank the State Water Resources Control Board members and the staff, first, from a year ago, when they started for the first draft. They listened and they moved. And we listened and we moved. Actually, a long way, those of you who recall what the first proposals are on the table, and you see what is in front of us today, they really should be acknowledged for listening that much and getting to where it is, both the long way, a lot better, and I am sure that many of the audience will acknowledge that, even though, if it did not go all the way that everybody would like to think. Also, I would like to thank them for acknowledging the significant of sub-liability [18:09]. They always said, "We want to implement a policy, but we are not going to be the entity responsible for having the lights go off." And particularly the proposals in front of us, we take high comfort from the fact it is a bi-annual review process to review the progress towards achieving the Board's objective, but as important, the state of the grid and its readiness to actually accept whatever happens at that time. We all know that there are sometimes lines that are set in the proposals and it is a more than best effort, it is diligence, it is a study, and a commitment to do so. But we also know that there are many moving parts there, and many dynamics that will play a role, including permits, costs, among other things. So the fact that every two years we will sit together with all integrity to review the progress towards achieving both goals for the eyes that provide a reasonable level of comfort. So I look forward to the rest of the day and I thank you, Commissioner, for taking the lead and organizing this.

COMMISSIONER BYRON: Gentlemen, thank you for your perspectives, very helpful. And so we will move on now and Dr. Jaske will give us the first presentation. Mike, I point out to you that we are ahead of schedule, so it is your responsibility from now on to make sure we stay on schedule. We have got a lot of content here and I certainly want to make sure we have ample opportunity to get some input. So thank you for putting together such a packed day for us. So I think you are going to take us here on an 11-step program. Is that right?

Agenda Item 3: Energy Agencies' Proposal on Impact of OTC Plants on State Procurement Processes

DR. JASKE: Yes, sir. For the record, Mike Jaske, staff member of California Energy Commission. First of all, I want to point out that what I am going to provide as an overview here in the next half hour or so is a summary of what is in the actual document that was authored by members, each, of the Energy Commission, PUC, and CAISO, a document entitled "Implementation of Once-Through Cooling Mitigation Through Energy Infrastructure Planning and Procurement." A mouthful. But that really is the nut of what we have proposed to the Water Board and what the Water Board staff has agreed to accept and include in their Substitute Environmental Document. And speaking of the Water Board, I want to acknowledge the presence of Mr. John Bishop in the audience today, Chief Deputy Director of the State Water Resources Control Board, and the lead person in their endeavor to bring this proposal together and seeing it through to an adopted policy by the end of this year.

I think we already talked about purpose. Let me just say that -- and you at the dais have basically stolen what I was going to say, but I am glad to hear you say it because, really, what we have in front of us is the three energy agencies -- for purposes of today, calling the ISO an agency -- agreeing not only to work together, but to work with the Water Board over the course of probably a decade or more, to make this change-out happen, and that is how precisely we are going to accomplish that, what little stumbles happen along the way, what delays may be encountered in this or that dimension of it are unknown, but as you have all acknowledged, we are embarking on a new adventure here.

The essence of the proposal is that, in most instances, installation of wet cooling towers in these old plants is not either feasible, or it is too expensive given their remaining life, their efficiency. Therefore, we expect these plants will retire, some sooner, some later, some will re-power, they are in a good site, the ability to continue to use that site in the transmission infrastructure is the proper thing to do, let's take advantage of that. And, as Commissioner Boyd said, in many other instances, some other element of preferred resource additions is what we will be striving to bring into play as the replacement for the capacity to retires. Again, as everyone has acknowledged, reliability is our objective. I do not need to add, it is our constraint, as Mr. Mansour did not use that term, but I think that, in effect, is the reality of it, we have to assure reliability is in place at all times, and the many separate manifestations of what that means. The total resources are there that meet the system requirements, that where there are load pockets and local reliability areas that we satisfy the capacity requirements of those particular geographic areas, and also that we assure that we have the right mix of resources that allows the ISO to operate the system in a way that meets the needs, not only the needs as the system is today, but as it will continue to evolve through time, as we have different resources and there will be complimentary obligations, or requirements, to have the statutible resources.

So we are going to be relying upon the analytic planning and permitting activities among the energy agencies, improve the coordination of those, build upon them, tighten those linkages, and try to move as quickly as is possible to bring to bear replacement infrastructure, whether that is generating capacity, demand-side measures, new transmission system projects, a whole panoply of options, as Mr. Boyd pointed out.

What is included in Appendix B of the Staff Report and also included within the document that the Water Board published as its Substitute environment document is our best thinking as to the schedule for the bringing on line of replacement infrastructure for each of the OTC plans. Some of those plants have a much clearer path toward the fruition of this replacement infrastructure, and some is very cloudy, particularly in Southern California, it is very clear how that complicated area that has numerous difficulties of bringing new infrastructure into play can accomplish that in as rapid a manner as many of those who have been advocating for OTC mitigation would like. But the essence of the proposal is to recognize that we need to do that, and to put these processes together as best we can and as quickly as we can to cause that repowering away from OTC or replacement infrastructure to come into being. And then, as Mr. Mansour says, we are going to revisit this periodically. As circumstances change, either for individual components of the OTC fleet, particularly replacement projects that suffer delays or slowdowns, or problems, those kind of tweaks, if you want to call it, to the plan, or if there is something major and systematic that affects a large number of the plants that may delay a whole number of them, clearly, those are critical elements that need to be recognized, need to be overcome to the extent that those difficulties can be, and the Water Board needs to be informed so as to assure that the existing plants can be permitted to run a little bit longer if that is the only solution.

So in the Joint Staff paper, there are 11 steps, which I will just very quickly run through them here, and then dwell on a limited number of them later in my presentation, just to give a clearer sense of how they will work. These words in this kind of a PowerPoint presentation are a poor substitute for the document, itself. So I refer those of you who have questions to the main report; rely on its wording. We labored long and hard to get those words right, that we could agree to, at least. And these are my words.

So we are going to make use of existing studies that inform us as best we can. We are going to conduct new analyses, probably a number of them over time, periodically, quite exactly what frequency is still a little unclear. Once we have the results of those analyses, as well as the things we already understand fairly well, we can put together a plan. We are going to provide that plan as an update to what is presently in the Water Board's document; we expect that they and their regional boards will make use of that. There are particular problems with achieving that in Southern California, the issues of South Coast and its priority reserve are well understood, but the solution is not. And also, the dimension that Southern California portion of the ISO's balancing authority and the LAWP balancing authority are in the same air shed, yet they do not plan together, and somehow or other we need to reconcile the need for new power plants, repowered power plants, and scarce aircrafts.

As Commissioner Byron said, we need to modify procurement processes to make sure that we get the kind of replacements that are necessary. The ISO will be modifying its Annual Transmission Planning Process to bring elements of this into that process, and at some point perhaps identify and approve particular transmission projects. Once we have that first round of actual projects launched into the pipeline for approval or construction, we can update the plan and take that into account, inform the Water Board, and finalize the permits for the affected plants. We will continue to monitor and update the plan and update the Water Board periodically.

So now let me use just a few of the steps to explain more fully how this is going to work. For Step 1, we are going to make use of existing information where we can inform the Water Board as to the necessity for any individual one of these facilities to be relied upon for reliability, so I am using South Bay down in San Diego as an example. When Otai Mesa becomes operational a little later this year, then a portion of South Bay will no longer be needed. South Bay has four units, which is roughly 700 Megawatts. Somewhere in the vicinity of 200 to 300 Megawatts of that South Bay plant will no longer be necessary. We are not clear which ones of those four units would not be necessary; that remains to be examined, we have time to do that. Then, a few years further down the line, when the Sunrise power link is energized, we are now expecting the third quarter of 2012, then the remainder of

South Bay is no longer necessary. At that point, then, it is not critical to the local reliability of the system for that plant to remain operational. So, from the energy perspective, the Water Board can modify its permit. So that is an example of how projects already in the pipeline prior to OTC mitigation can be examined and put together as part of a OTC mitigation package.

Step 2, there are clearly new analyses that are necessary. The first part of that is developing scenarios of alternative resource build-outs. A lot of preferred resource policies, we do not know for sure how they will actually evolve through time. The only way to deal with that is to create scenarios that imagine different degrees of success, evaluate those scenarios relative to low forecasts, and then for some selection of them, decide which ones need further in-depth study. The ISO will conduct some extensions of what it has historically done for LCR, push those out further in time, evaluate these multiple generation and load scenarios, perhaps with alternative transmission configurations, figure out what that is going to mean in terms of local capacity requirements in these critical areas. We will review the results of that, juxtapose that against nominal retirement schedule that we have, and try to put something together that matches the ability to bring resources on line with

OTC plant retirement.

We also, as I said earlier, need to assure that we have the right kind of operating capacity the ISO needs to run the system. A variety of ramping capabilities, inking and decking a rig, perhaps even turn off and then turn on from cold condition, these old plants are considerably more flexible than new combined cycles and, so, how to configure resource additions that replace their characteristics is an important dimension of this study process. So we bring together the things that we have learned from a local perspective and things we have learned from the operating characteristics perspective, overall system requirements, to have our integrated view of all those particular pieces. And then a few -- for supplemental things, as I indicated earlier, the special issues having to do with LAWP, and then periodic updates, essentially bringing together a new view of the replacement schedule for all the OTC plants.

Once we have that analytic information and, to the extent that there are options within it, then we have the ingredients to present to the three agencies, and the agencies will need to make some choices. It is not necessarily the top down decisions, but where there are preferences for a certain course of action, that can be identified, the configuration of the IOU bids can proceed, or the examination of transmission in more detail by the

PTO's, to actually get down to proposed projects and their costs, the sort of thing that gives guidance to the entities who are going to actually put the rubber on the road. Once that plan has been put together, it will be the basis for updating what is in the Appendix B of the staff paper. That, in turn, then forms the foundation for the permits that State Board and its regional boards will issue to each of the plants.

As I said earlier, there is a particular issue with South Coast, but maybe extending to other Air Quality Management Districts where there are simply fewer and fewer air credits available for new power plants, particular conflict, if you want to call it that, between the Los Angeles portion of ISO and LAWP balancing authority, with very limited air credits in there, and we need to find some way of reconciling Southern California ISO and LAWP air credit needs. This may involve some changes to the Energy Commission's licensing process and Panel 3, this afternoon, will begin looking into these questions in more detail.

How does the procurement process need to change? Do we need to have narrowly targeted RFO's that select out the particular kinds of replacement capacity, either in location, or in the characteristics of the capacity, itself? How will market power issues that might arise from this be dealt with? Panels 1 and 2 are going to look into these kinds of issues, first, from the generator perspective, and then from the IOU perspective and the ratepayer perspective.

Transmission Planning. How are we going to refocus it to examine these OTC replacement issues? Can some of the assumptions of the planning and the analytic process be built into the unified planning assumptions that are used there? Are there special studies that are necessary, that are outside the current scope of the Annual Transmission Plan? Are there things that are appropriate for studying jointly between the ISO and LAWP? Panel 4 this afternoon, toward the end of the day, will look into some of these things in more detail. And then, the remaining Steps 8 through 11, I do not have anything really more to say about those now.

At the back end of Appendix A of the staff paper is a section that talks about unresolved issues and I will just list the five issues here, they are discussed in more detail there. Clearly, a huge one is this whole issue of air credits in South Coast. There is the question of how the RFO process, the IOU's, operate to procure resources juxtaposed with permitting at the Energy Commission of thermal resources that are the replacements, should that RFO come first and then permitting? Or should permitting come first and then RFOs? We will get into that in a little bit in one of the panels today. How are we going to assure that the operating characteristics that we end up deciding we need actually are present in the generating technologies that are licensed and procured? How do we assure that the inherent engineering characteristics of the power plants actually result in them being operated in a way that is necessary? Does ISO need to do anything different about its market design to make sure that those kinds of operating characteristics are compensated properly for being made available?

Of course, there is a host of issues associated with the nuclear generating facilities, San Onofre and Diablo Canyon. The Water Board's proposal calls for further analysis of the cost of shifting to wet cooling. I am sure we will hear over the course of time plenty from the SCE and PG&E about that subject. And finally, what is the nature of this Capital P Plan? You know, is it something that is so substantive that it allows for some sort of preferential treatment for the projects that are included in it? Or is it more a small p plan which provides just direction and guidance that the three agencies are pursuing in their own individual processes? That remains to be resolved.

So what comes next? We are looking for comment on the joint staff paper and all of the workshop discussion that happens today by August 11^{th}, as Ms. Korosec indicated earlier. The agency team will be reviewing those comments and making recommendations to Management. If we hear something that is very substantive, we may need to be updating our proposal to the Water Board, but, in any event, we are, I think, confident enough that the general direction that we have identified is correct, that we are going to begin doing some of the initial steps of implementation, which for the staff team involved, beginning to pull together some of the precursors to the analytic steps that we will be doing in more detail next year. And with that, I am finished with my presentation. And we now have a half hour and 45 minutes or so for clarifying questions, but what I would suggest is that representatives or authors of the joint paper come up to the panelist's table and then, if the Committee could recognize and call upon people who have clarifying questions, we will do what we can within the time available. I have been contacted by Edison and they have a number of questions, so if you would recognize Mr. Pizarro, we can get started.

COMMISSIONER BYRON: All right, Dr. Jaske, so if I understand it, the panels will come forward and Mr. Pizarro is going to make some comments at this time. Is that correct?

DR. JASKE: Questions, comments, however. He is the first and hopefully we have quite a few in our 45 minutes.

COMMISSIONER BYRON: Okay. I would like to start with the Dais, if we may, then. Commissioner Bohn indicated he has a question. Go right ahead, Commissioner.

COMMISSIONER BOHN: Yes, thank you. Mr. Jaske, in this extraordinarily complex process, I have heard only limited references to cost. Has there been -- is there ongoing or will there be any discussion as to the net incremental cost of this mitigation process? And I am interested now in sort of the financial cost because some of this stuff relates to taxpayers, some of it relates to the ratepayers, some of these plants are scheduled to go out of operation at some point, and it would be inherent cost involved in upgrading and the rest, but there is a nugget in there as to the cost enforced on the economy of the State of California for this mitigation. Have you all done any work on that? And, if so, what is it?

DR. JASKE: There has been very limited work done on that subject. The most clear-cut public example of that is a preliminary transmission study that ISO did last spring -- or, excuse me, last fall, it is listed on their website. It is very difficult to disentangle the sort of business-as-usual costs going forward as low grows, as natural expansion of the system would be required, versus the incremental costs associated just with OTC. But there is a very preliminary piece of work done. Dennis, did you want to add to that?

MR. PETERS: Well, that study that Mike references is really sort of a worse case scenario of situations whereby most plants would retire, and what would be the resulting transmission solution. What we concluded, and the biggest impact was to Southern California, was that approximately $4-5 billion of transmission would be needed to replace the reliability needs for L.A. Basin Area. Now, that did not take into account the replacement generation on the other end of those lines, nor did it take into account potential voltage support issues within the L.A. Basin. So that was really sort of a bookend of the worse scenario. The bigger issue than cost really had to do with feasibility, feasibility of building multiple 500 kV transmission lines into the L.A. Basin is obviously very controversial and it would be very difficult to do.

COMMISSIONER BOHN: As we plan, as we go forward in the planning process, is there any mechanism in place to try to tease out the incremental costs? Because, as we go through talking with the utilities and socking the ratepayers with the cost, since this is a statewide enterprise and goal, the allocation of the impact between the taxpayers and the ratepayers and the various and sundry people on whose backs this has to ride, it seems to me that is an important consideration; it does not mean we should not do it, but as we at the PUC need to deal with the role that the ratepayers play, it would be very helpful if there was some sort of incremental impact analysis relative to cost.

COMMISSIONER BYRON: Commissioner, if I just may take a moment, a little bit out of order, we should introduce the gentlemen that are with Dr. Jaske here, and I apologize. Dennis Peters from the Independent System Operator, and Robert Strauss from the Public Utilities Commission. And I would like to thank all of you because I know how much you have been working on this over the last number of months, and it is my failure that I have not introduced you to start with. Nevertheless, we have more questions, I am sure. Commissioner Bohn, do you have more?

Just a couple of quick questions on my part. As you were talking there, we have a working group that has been underway for a while; it would seem to me that, in the analysis you have done at this point, it is based upon the limited amount of information we have available to us. How key is the information that you received from others that need to participate going forward, such as, as Commissioner Bohn indicated, the investor-owned utilities, the publicly-owned utilities, the independent power producers, when do we start integrating them? Gentlemen, what are your thoughts on this?

MR. PETERS: I will take a stab at that. I think the way the plan is written, so far, from the Water Board, it requires generators to utilize once-through cooling to put forth implementation plans within the first six months after the policy is effective. And certainly, that will be information that will be useful to us in terms of putting together a plan. The plan, itself, as the energy agencies have put together and proposed, would inform two different processes, one would be the CPUC's Long-Term Procurement Plan. It would also inform the ISO's transmission planning process, not necessarily the unified planning assumptions, but rather the scenario analyses that would look at various options of transmission and generation as solutions. We would widely start those scenario analyses in the 2011 planning process for the 2011 Transmission Plan.

COMMISSIONER BYRON: Mr. Strauss.

MR. STRAUSS: It is also 2010 Long-Term Procurement Plans, which that process will start at the end of this year, will include the analysis of once-through cooling. And there is going to be multiple scenario analysis of how the -- both for the statewide need, and this will definitely impact the local need requirements to meet the need for resources statewide, plus the bundle to the utilities, which will need to be integrated in that process. And we are just beginning that process. And the staff put out a staff proposal on how to modify the Long-Term Procurement Plan going forward, to do a more integrated analysis than had been done in the past.

COMMISSIONER BYRON: Dr. Jaske, did you want to add anything?

DR. JASKE: We are aware that some of the IOUs, either in their procurement side, or transmission side, are sort of eager to have a level of discussion that we have not yet engaged in with them, so that is probably something that can happen now, that we have a document presented to the Water Board, and it looks like the Water Board is going down this path. We have enough comfort that we are ready to have those kinds of discussions.

COMMISSIONER BYRON: Gentlemen, I would like to go ahead and open it up. I had mentioned Mr. Pizarro is here from Southern California Edison and we actually had a meeting last week. And we appreciate you being here. If you would like to ask any questions or make any comments at this time, you can start off the public aspect of this. I would like to thank you very much for being here. I note, you know, Sacramento is awfully close -- how can I say this -- the Energy Commission is awfully close to what goes on here in the Capitol and Mr. Mansour is a few miles away, and Mr. Bohn has gotten a little further away in San Francisco, but Los Angeles is, you know, out of mind. And so maybe there is an advantage to being at this distance, but it also affects communications at times. I appreciate very much your taking the time to be here, I know this is important to you and your company and I am very interested to hear what you have to say.

MR. PIZARRO: Commissioner Byron, thank you. And thanks to the rest of the panel and the staff that assembled this really important meeting. For the record, I am Pedro Pizarro, Executive Vice President of Power Operations at Southern California Edison. And I would like to start by thanking the State Water Board and the energy agencies for the clear, open collaboration to the Draft OTC policies, and particularly the energy agencies for the focus and ensuring the reliability of California's electricity supply. At SCE, we support the Water Board's overall goal of protecting marine life, and so the question we must answer now is, how do we best accomplish that goal in an environmentally responsible, reliable, and consumer cost-conscious way. So my comments are aimed at this objective.

Now, if we are speaking to the infrastructure and system planning specifics of the policy and the inter-agency recommendations, I would like to address our over-arching recommendations on the Draft Policy. And first, I would like to pick up on Commissioner Bohn's question on cost because the first one I would like to make is that SCE urges the State Water Board to conduct a cost benefit analysis of the statewide draft policy to determine the appropriate standard of performance. Currently, the draft policy requires closed cycle cooling or its equivalent as the best technology available. We ask that this should be re-visited and conduct a cost benefit analysis, which may show that the costs of closed cycle cooling are significantly greater than the benefits produced. In such a case, the Water Board should specify the practical and cost beneficial steps to protect marine organisms. Such an approach is appropriate and, we think, encouraged by the recent *Riverkeeper* Supreme Court decision. Secondly, SCE recommends that the energy agencies that are charged with ensuring the electric reliability view, the PUC, the CEC, the CAISO, advise the Water Board on the feasibility of implementation and compliance timelines with respect to reliability in the electric system as we move forward, instead of having the broader proposed statewide advisory committee on cooling and water intake structures. To the extent that the input of the other agencies is needed, and I am sure it will be, the CPUC, CEC, and CAISO can consult with those other agencies to obtain their expertise. But given that the key questions will be around electrical reliability, we believe that the three -- your three agencies -- are the right home for that discussion. Third, SCE urges policy makers to ensure that the cost of OTC policy compliance are borne by all benefitting customers. The current draft references for procurement by utilities, most exclusively, without reference to other types of load serving entities in our retail market. Energy agencies should address replacement capacity approaches that ensure costs are spread fairly across the entire California system, not just carried by bundled utility customers, alone. Eventually, for capacity market, but prior to that through procurement with fair allocation of cost responsibility. And, fourth, the Water Board and energy agencies must ensure that the environmental impacts caused by the elimination of OTC are not greater than the environmental impacts of the once-through cooling, itself. And policy makers should be mindful that closed cycle cooling has significant adverse environmental impacts and very significant costs. For example, a move to lower efficiency closed cycle cooling will cause an increase in greenhouse gas emissions and smog forming and particulate [inaudible][55:45] two and a half emissions. Further, nuclear plants play a critical role in meeting California's

GHG emission reduction goals. Even if closed cycle cooling could be accommodated at the nuclear plants, which for SONGS certainly is highly unlikely, requiring the transition to closed cycle cooling would mean the emission of large amounts of pollutants from replacement power during the time required to retrofit the nuclear plants and due to the lower efficiency of the nuclear plants after transitioning to closed cycle cooling. This is particularly troubling in the case of San Onofre because the plant has already fully mitigated its adverse ocean water impacts, and I will say more about that in a minute.

I would like to speak specifically about the draft policy as it relates to California's nuclear plants, then quickly touch on fossil plants. I noticed we had an emphasis on SONGS here. It is important to keep in mind first, though, that nuclear plants provide more than just low cost base load energy. SONGS supports grid reliability by supplying significant amounts of reactive power, or Megawatts, to prevent voltage collapse. The transmission necessary to replace the same level of grid reliability provided by SONGS would take up to eight to 10 years to license and build, and would cost electricity consumers between $300 million and $800 million, assuming it could be licensed successfully, which, as we all know, has some real challenges, really, throughout the country. First, SCS, the Water Board, and energy agencies, to determine that SONGS has already complied with the Draft Policies Special Studies Requirement, and confirmed that SONGS has already mitigated any detrimental impact to marine life, resulting from its use of once-through cooling. The special studies required by the draft policy are to investigate alternatives for nuclear plants to meet the requirements, but SONGS was already subjected to such studies by the California Coastal Commission. Those studies would stretch over a decade and included many public hearings, resulting in a decision by the Coastal Commission that the cost and the environmental impact of cooling towers at SONGS were not reasonable or warranted compared to restoration and mitigation options that were designed by the Coastal Commission. SONGS has already performed mitigation measures that restore any adverse impact on marine life caused by the plant's operation and, in fact, it has contributed back and added margin. Rate- payers have already for an extensive study of SONGS in addition to the mitigation measures, and they should not be required to fund the same studies and mitigations all over again. Our ratepayers have spent more than $200 million for in-plant technology to reduce entrainment and impingement, and return fish safely to the ocean. They have spent $50 million in advance study research, $5 million on a fish hatchery, $46 million on the 175-acre Wheeler North Reef off San Clemente, which is the largest environmental project of its kind in the country, and $90 million of 150-acres of the San Dieguito Wetlands Restoration Project in Del Mar. Secondly, we also ask that the Water Board reconsider aspects of the policy that may create operational safety issues at SONGS; for example, the requirement for a large organism exclusion device may cause clogging of the plant's cooling water intake, potentially creating an operational safety issue due to the reduction and intake of cooling water. In addition, to the extent cooling towers are required, most would have to be built on the inland side of the site, very near Interstate 5. For those of you who have seen San Onofre, you know that there is not much land there. And among the problems that we saw from placing cooling towers next to the Interstate Freeway, where we saw plumes from the evaporative cooling towers, which pose a significant traffic hazard and habitual impact.

Turning very briefly now to the fossil fuel plants, the ISO's recent Integration of Renewable Resources Study indicates that all the OTC plants are needed to integrate 20 percent renewals. CAISO stated [quote], "The good news is that this study shows that the civility of maintaining reliable electric service with the expected level of intermittent renewable resources associated with the current 20 percent RPS, provided that existing generation remains available to provide back-up generation and essential reliability services." [End of quote]

At SCE, we are working to support new capacity, but litigation surrounding the priority reserve, which has been brought up already, has blocked that effort. We currently have 1,750 Megawatts of contracts for new generation that cannot obtain air emissions clearance. SCE is in a position where the draft policy may force the owners of plants to retire these critical resources, yet we will be unable to help replace them in time directly through our IPP partners. Moreover, none of these considerations address the need for existing generation if the state decides to go beyond 20 percent RPS and raise to build at 33 percent. So we recommend the following: First, flexible timelines are needed to conduct studies and feasibly implement eventual retirement of OTC fossil plants without undesirable reliability and rate impacts. Replacing more than 30 percent of California's generating capacity is likely to take decades, and not just seven to nine years as contemplated in the draft policy, due to licensing, grid reliability, and other issues. The South Coast Air Quality Management District Air Pollution Credits issue has to be permanently resolved before we can develop a comprehensive OTC replacement plan -- for Southern California, at least. Multiple other elements will affect timing -- generator siting, generator financing, transmission interconnections, and the interplay between the procurement actions and independent generation market dynamics. And I think the panel on procurement where Kevin Cini, our V.P. for Energy Supply and Management, will speak and address those issues further. So all these challenges require a flexible implementation timeline. And, secondly, we need to retain and expand the site-specific cost benefit analysis in the draft policy. We appreciate that that is there, we also appreciate the two-year review, but currently the draft policy limits to site-specific cost benefit analysis to nuclear plants and to fossil plants with an 8,500 Btu per kilowatt hour heat rate or less. We urge the Water Board and we urge the energy agencies to encourage the Water Board to provide an option for all OTC plants to demonstrate whether or not the cost of implementing the policy or holding is proportionate to the environmental benefits to be gained. If the site specific cost benefit analysis shows a disproportionate cost to benefit, the State Water Board should then specify practical and cost beneficial steps to protect marine organisms that are cost beneficial at each site and, again, coming back full circle to Commissioner Bohn's comment on cost.

So, in conclusion, we urge the Water Board and the energy agencies not to view the OTC policy in isolation; instead, policy makers have to examine this policy in the context of the state's other energy and environmental goals. During this time of economic downturn, policy makers also have to be mindful of cost on the state's energy consumers, whether as taxpayers or ratepayers. SCE stands ready to help the Water Board and the energy agencies to achieve the ultimate goal, the real goal, of preserving marine life in a way that preserves reliability and is environmentally responsible and also is mindful of cost. So thanks again for giving me the opportunity to make comments, and I would be happy to address any questions.

COMMISSIONER BYRON: Thank you, Mr. Pizarro. Very well prepared, obviously, your comments. Any questions for Mr. Pizarro? I appreciate the input you provided. I would hearken to address one issue.

MR. PIZARRO: Sure.

COMMISSIONER BYRON: You had indicated, I thought I heard you correctly, priority reserve will have to be resolved in a permanent way before we can address once-through cooling. And I am going to go back to Commissioner Boyd's comments about bisecting these issues -- or dissecting these issues, I should say -- we are going to need an integrative approach that probably addresses those two issues simultaneously, we are not going to be able to separate them.

MR. PIZARRO: And I think we are probably saying the same thing with slightly different twists. The point is, we certainly cannot see a clearer picture of how you solve one without the other, and with the uncertainty of priority reserve hanging over the collective heads in Southern California, we have no ability to provide a credible timeline for when those plants come on line, let alone other parts of plants that might be needed in the future to further support replacements of existing capacity. So, you know, I think these have to be looked at in tandem, but the point, you know, I really wanted to make was, it certainly cannot solve the OTC timeline issue until we have some visibility to the priority reserve timeline issue.

COMMISSIONER BYRON: Good. Mr. Pizarro, thank you for coming.

MR. PIZARRO: Well, thanks for having me.

COMMISSIONER BYRON: I appreciate your comments. Are there others who would like to make comments or ask questions at this time, based upon Dr. Jaske's presentation? We have got the right folks at the table.

Any other questions or comments? Please identify yourself.

MR. NELSON: Hi, my name is David Nelson and I am with the Coastal Alliance on Plant Extension. We were Interveners in the Morro Bay Power Plant. We are 10-years-old and we have been watching this issue for quite a while. One question I would have is, in the documents, not the CAISO, but the Water Board document, there is a counting that has to be done. Morro Bay is shown as 1,002 Megawatts and, when we talk about 20 or 30 percent of our energy coming through once-through cooling, I would like to see better numbers available. You have Morro Bay listed right now and using numbers from 2001 to 2005, having 18 percent capacity right now. And the truth of the matter is that, to go back five or six years, or back to the energy crisis, really skews how important these plants are to the system, and I am afraid that it is getting lost in figures, in accounting figures. Morro Bay really -- and I will speak more to Morro Bay and, say, Moss Landing, I am not going to go near nuclear power plants, I understand they have a huge function in our state and they need to be deal with different, but just those two power plants, looking at Morro Bay, it ran zero last year and our lights did not go out. I really object to the whole idea of our lights going out, the whole fear aspect to this. I, too, would really love to see a resolution to this problem. And this is one of the problems, is that when you show a power plant as contributing 1,000 Megawatts to the overall California energy production, and it really does not come anywhere close to that, you are exaggerating how much we need this once-through cooling. Now, we have a lot of independent owners in here, and people who abuse this water, and I heard the Commissioner talking about the benefit and the expense of this to ratepayers; nobody has ever talked about the benefit of the once-through cooling water to all these power plants, and they all have a benefit, they all make higher efficiency because of the cold water. But nobody ever took that into account until they asked to put dry cooling in place, but then there was a big energy penalty, which I might add, in the Water Board document now, that energy penalty had shrunk from -- I think, at Moss Landing, they were claiming like over six percent energy penalty down to a percent and a half, now that the threat of a fee for water because of the energy benefit is there. So these are kind of the things we have got to look at. And the other thing, the major thing, is we heard the gentleman from Southern Edison talking about -- I am sorry, I am not quite as prepared as he is, but I do not make as much money, either -- the expense of this, and he wants a cost analysis, and again, back to the document from the Water

Board, they are using the cost benefit analysis done at Moss Landing, and we were a very young organization at that time and it was our first "cutting our teeth," so to speak up there, and the way the Water Board did that cost analysis is just incredibly wrong for the state. And we, as a young group, saw what dry cooling systems being built in the deserts and we went up to Moss Landing, which is as you all know, nice and cool in the summer when you are really making energy, and we said, "Well, why don't you put dry cooling on your combined cycle generators?" "Oh, it'll cost too much," and then you go into the environmental -- and now, this is the big point -- you want a cost benefit, but nobody is telling -- nobody can show -- and I have sat at the technical working committees and asked the scientists -- but everybody comes to an agreement to what level we value the environment, and the problem here is that we are not putting in the full value on the environment, and that is the big problem. I mean, when you discount everything except commercial fish and viable crab larvae and things, you discount everything else in the environment. So that is the big problem with this cost analysis benefit. And Second Circuit Court, the *Riverkeeper* was very clear about that, that you should not be making up ways to adjust for the environmental damage, you cannot really account for it, and so it is all subjective. And most of the input on this is coming from IOUs and big energy producers, so, you know, it is quick to discount the environment. So, from that point, from what was said this morning, those are the tripping points that I, as somebody who is watching what is going on, and Morro Bay, to me, it is just wrong to continue even out past what its contract is now. Their contracted until 2011, and for the amount of energy that they make, it is just not justified to continue the damage that is going on there. So that is it. I will wait for a while and come back. Thank you.

COMMISSIONER BYRON: Mr. Nelson, thanks for being here. Thanks for your comments. I think that your comments demonstrate, obviously, concerns about the environment, and you covered a spectrum of issues. It is a very complicated issue, which is why all these agencies are involved. I encourage you to continue to learn more and more about how complex this is. I have worked in this industry for a long time, from many different perspectives, and I can tell you, just when I begin to think I understand it, I realize I do not. So that is why we are working together to try and promulgate a rule that meets the law, that addresses the environmental concerns, but at the same time addresses the reliability needs of the state and its economy. So I encourage you to stay involved, we welcome your participation, even though you do not make as much as Mr. Pizarro. Dr. Jaske, did you want to add anything or say anything that might be helpful here?

DR. JASKE: Mr. Nelson was referring to capacity factors that we have reported in the Water Board Substitute Environmental Document. If you are interested in more information about those, the Energy Commission's comments to the Water Board, dated May 20th, 2008, that are on the Water Board's website, has an appendix as annual capacity factors, I believe, from 2000 to 2007, and then monthly capacity factors for each plant for 2006 and 2007, so you can see how it is that various OTC plants are actually being operated.

COMMISSIONER BYRON: Thank you. Sir, please identify yourself.

MR. GEEVER: If I can, very quickly, my name is Joe Geever, I am the California Policy Coordinator with Surfrider Foundation, and we were under the impression, and I have heard it repeated several times, that today's session was not going to be a debate on the State Water Resources Control Board's Policy, yet the first two public comments were exactly that.

COMMISSIONER BYRON: Well, then you will not be the third.

MR. GEEVER: We came up here to appear, you know, the information on what this meeting was supposed to be about, and so we look forward to getting back on that. If Southern California Edison wants to debate the Water Board's policy, there will be forums for that. I was under the impression that this was not it. Thank you.

COMMISSIONER BYRON: Thank you. Mr. Kelly.

MR. KELLY: Thank you, Commissioner. Steven Kelly, Policy Director for Independent Energy Producers Association. And I want to follow-up on some of the comments Mr. Pizarro made, related to the need for flexibility as we move forward, and also find that, from the business perspective, that there is a schedule that is proscribed and a lay-out that the staff has worked hard on detailing, which is very helpful to send signals to the marketplace. The concern that I have had in initially reading the report is the policy objective, which is to create a commitment for the generation to be there until there is an operational replacement entity that is operational. As we all know, it is very difficult to forecast when a new transmission line is actually going to be energized, when new generation is actually going to come on line, in spite of the best expectations in the planning processes that we have. So there definitely needs to be flexibility built into this mechanism as we move forward. And I would also urge, to add onto it, and Mr. Pizarro talked about it, is a need for these kind of clear trigger points to the business side of things, the generation side, that if you are intending to remove an asset that is already in place when something else is operational, that you send that signal in advance, and not next month by way of shutting down. There are a lot of decisions that have to be made by any asset of this size, if they are going to modify their operations. And the sooner that you could send those signals probably the better. I understand the need that replacement assets be operational in order to serve the goal that the ISO has to maintain grid reliability, but we have to figure out a process that conjoins those -- the needs for reliability and the need to send proper signals to the business community as they move forward and make decisions about investments and so forth. And that probably speaks to some sort of flexible process that has, I think, trigger points for agency decisions -- CPUC decisions, and something else following on that. I think that will be important.

COMMISSIONER BYRON: Point well taken, Mr. Kelly. And, of course, I think, besides the flexibility that you are looking for, that everybody is looking for in a rule that would be promulgated, we hope by the Resource Control Board, is a certain amount of forthcomingness on the part of all the industry participants. This is a competitive environment and that makes it a little more challenging; the State does not control or operate these assets, but we have some jurisdiction over various aspects of them. So it is definitely a cooperation going forward if we are going to be sending the various price or market signals, as you indicate, as much in advance as possible for you to make business decisions, and a sense of what your plans -- your members' plans are -- for these power plants, as well.

MR. KELLY: Yes.

COMMISSIONER BYRON: Thank you.

MR. SIMPSON: Good morning. I am Rob Simpson. I am representing Californians for Renewable Energy, or CARE. Our interest is in stopping this once-through cooling, but also the next step. When we look at the next step and we see projects like the Humboldt Bay Repower Project, that was marketed by PG&E as being eight percent cleaner, but you see documents demonstrated that it is five times dirtier than the existing plant, we look at plants like Carlsbad, which claims to be eliminating the once-through cooling, but still plans to use ocean waters, but they are just renaming it something different, each plant that I see coming forward -- I see Avenal in the middle of the state that claims to be a plan to replace once-through cooling, but it plans to use fresh water from the California Delta, or Aqueduct. The next step, for us, we do not believe the next step is to run wires out into the desert to some renewable facility that is not yet there. The next step is not to find a way around the Clean Air Act, to put more pollutants in the air in Southern California, the next step for us feels that it should be renewable, and while it is not right in front of our nose, it is right on our roof, renewable energy in the load centers, we feel that that can be much quicker than new fossil fuel fired generation and it will serve the people of California better. Thank you.

COMMISSIONER BYRON: Thank you. If there are no further comments or questions, I am going to propose that we continue moving because we take our best guess at the agenda in terms of putting panels together, we have a one-hour panel coming up with many participants, so let's go ahead and ask those panelists to come forward. Dr. Jaske, is the idea to have them sit around the table here, as well? Gentlemen, thank you very much and do not go anywhere because I am sure there are going to be more questions for you later.

Agenda Item 4: Panel 1: Changes to IOU Procurement from a Generator/Developer/Bidder Point of View

DR. JASKE: As the panel is coming forward, let me say that Simon Baker of the PUC Energy Division will be the moderator, and I will have him introduce the panel.

COMMISSIONER BYRON: Great, great. All right, gentlemen, if you will come forward, and I would ask, if you would not mind, if you have a name plate in front of you, after the audience has had a chance to see it, if you would not mind turning it around, we would appreciate that.

MR. BAKER: It looks like I will be at the podium.

COMMISSIONER BYRON: And you get the podium. Welcome, we are glad to have you.

MR. BAKER: Uh, good morning. For the record, I am Simon Baker, with the CPUC's Energy Division in the Long-Term Procurement Proceeding. I would like to begin today by laying the foundation for subsequent panels, Panels 1 and 2, on how we deal with the OTC issues through the PUC procurement process. And to do so, I have brought a presentation which is much more detailed and longer than I plan to get into here today, but it is provided as a resource because I know it will be available on the CEC website for stakeholders to review and inform themselves about our general procurement rules.

The Procurement and Resource Adequacy Programs are principally guided by Public Utility Codes 380 and 454.5. The RA Program obligates load serving entities to procure sufficient resources to meet system and local area needs with sufficient planning reserve margin, as well. And the procurement program under 454.5 essentially brought the utilities back into the procurement business, and it changed the structure of compliance, excuse me, the structure of cost recovery from one of after-the-fact reasonableness reviews to a preapproval and compliance framework. In the Commission's administration of these programs, our over-arching objective is to enable the electric corporations to fulfill their obligations to serve their customers at just and reasonable rates.

Now, at a very high level, the procurement program has essentially two parts. The first has to do with the Commission approving long-term plans, either 10-year plans that the utilities file, and the Commission adopts those plans with any necessary modifications. The second aspect of the procurement program has to do with the procurement rules, which are essentially upfront rules established by the Commission, which, when the utilities comply with those rules and their procurement, they essentially have preapproval of recovery of those costs, and then there is subsequent compliance review to ensure that the rules are being followed.

Today's workshop touches on both of these areas. The presentation that was brought by Mr. Jaske suggests that the 2010 Long-Term Procurement Plan will be an important nexus, as a first step, engaging the procurement process towards solving this problem. And there is a variety of analyses that are likely to need to take place in the long-term planning process, and in the Commission's approval of the next utility plans. As Mr. Strauss mentioned, the Energy Division recently submitted a proposal to our Commission for refinements to the utilities' long-term planning process that would enable the source of analyses that are envisioned to be required to fulfill the joint energy agency proposal. However, that set of analyses and the required modifications to the planning process, those are not the subject of today's workshop. The subject of today's workshop is focusing more on the implementation of procurement, and procurement activities such as requests for offers or competitive solicitations for new generation. So the remainder of my presentation will be focused on that latter aspect.

The procurement rules essentially break down procurement projects into three lengths of contracts, short, medium, and long-term. A long-term contract is any contract longer than five-years in length, and for that product category, there is a requirement that the utility file an application with the Commission for approval of cost recovery for those assets. In general, the Commission has a competitive markets first policy as a means of controlling costs to meet procurement needs. In the bid evaluation process, the Commission has mechanisms to internalize the externalities such as greenhouse gasses.

There is a greenhouse gas adder that is used as kind of a weight on the scale to compare various bids. And in addition, there is environmental performance standards which essentially limits any long-term commitments of the utilities to fossil assets to emissions rates that are equivalent to a combined cycle power plant.

For new generation needed to meet system or local capacity needs, the Commission has adopted a cost allocation mechanism which essentially spreads the benefits and costs of new generation to all benefitting customers. The CAM is eligible for new and repowered assets, it is not eligible for utility-owned generation assets. And, mechanically, the IOU is -- the rule is structured so that the IOU elects whether to utilize the CAM at the time of the application.

The Commission has implemented a procurement review group, which is a body of non-market participants, which serve on advisory basis. The utilities bring summaries of the various procurement activities to the PRG for review and vetting, and the primary purpose of the PRG is to speed discovery and minimize disputes in the Commission's decision-making process. A additional subset of the PRG is the CAM Group, which is represented by electric service providers, and community choice aggregators, and other non-IOU LSE's that are subject to the cost allocation mechanisms, so they have a seat at the table in decisions that are being made about new resources that are then the cost at which is then allocated to all benefitting customers.

In the RFO process, the Commission requires the use of an independent evaluator and, when it comes to the design of the RFO, the real crux of this issue when it comes to OTC is, what are the product specifications? And what I would like to focus on in this panel, and with the list of questions for this panel, what this is meant to address, is really what modifications are needed in this area, which is how do you translate what the needs are of the system for reliability into what the market actually provides to the competitive process.

In the RFO process, when bid documents are prepared, the IOUs are required to review those bid documents with the PRG, the independent evaluator, and with the PUC's Energy Division. And any differences or disputes that are raised in the PRG meetings, those differences must be resolved with Energy Division prior to release of the bid documents.

The most recent LTBP decision gave the IOUs specific direction. That decision was 0712052. It authorized new resources for all three of the IOUs, subject to various criteria, and those criteria address various policy objectives, including reduction of OTC, preference for brown fields development, and to be consistent with AB 1576, just as an aside, AB 1576 is legislation that essentially codifies a preference for brown fields development for new generation, and it encourages the Public Utility Commission to implement that preference through a cost of service model, essentially bilateral negotiations, open book bilateral negotiations, for cost plus to replace specific plants that could not be replaced through a competitive process. Various proposals to implement AB 1576 were presented in the previous Long-Term Procurement Plan proceeding, however, in the decision, the Commission did not adopt any specific recommendations related to AB 1576. In addition, the authority for new generation in the last decision was meant to fulfill policy objectives such as enhancing air quality and also reducing greenhouse gas emissions. The Commission required the utilities to make a showing in their application for new resources that the various policy objectives, which I listed, are being achieved from the specific resources that are brought before the Commission for approval. And the decision also acknowledged the need to strike a balance between achieving the objective of inducing retirements or encouraging repowering of aging plants, and containing costs. And this is really the tension which has been previously mentioned today, but I think it is the elephant in the room, and it is the biggest problem we have as we address this, in order to be able to achieve our OTC objectives and also maintain just and reasonable rates.

So with that, I would like to segue to today's panel. As we have heard, modifications to the procurement process are one of the elements of the joint agency proposal. And conceptually, there are really three approaches to solving the OTC problem with elimination of OTC from specific plants. Looked at from a need perspective, those three approaches are first to build new transmission to address the issue, secondly, to build new generation, whether that comes from green fields, brown fields, or repowers on-site, and those are separate deal structures and need to be considered in the RFO process. And finally, the third approach is to just avoid the retirement of the specific plant altogether through a refitting of the cooling system. That third category is not something that our procurement process has really had to deal with in the past, and we are very interested in hearing from particularly this group of panelists about how RFO products could be structured to encourage that third category. There were some preliminary remarks on the part of Mr. Jaske that you have heard in previous workshops that that third category is unlikely to be cost-effective, but we would like to hear confirmation, as well, from generation owners to what degree refitting of the cooling system is potentially cost-effective.

The PUC procurement process really deals with those two latter two approaches. There are two communities that are associated with that, we have the developer/generator community, and that is the purpose of this panel, and then the utilities themselves are the second community. So, with that, I would like to ask for the panelists to first introduce themselves, and then I will take the floor again with some final preliminary remarks. Maybe we will just start up here with you, Alan, please.

COMMISSIONER BYRON: If you would not mind, please introduce yourself, your company, and just a brief background on your company, not from a commercial perspective, but just so everyone, I think, in our audience will understand your role in this particular role and interest in this particular issue.

MR. COMNES: Sure. My name is Alan Comnes. I am a Director of Asset Management for NRG Energy, Incorporated. I oversee asset management issues for our West Region. In the West, we have 2,200 Megawatts of capacity, all in the eyes of the control grid, it is all in SB 15. Of that, about 1,600 Megawatts relies on once-through cooling, currently. One of our sites was recently repowered under a

Long-Term PPA with Southern California Edison and, as part of that, we eliminated once-through cooling at the site that is at Long Beach. So, since, we have adapted both aspects of the technology. Simon, do you want me to --

MR. BAKER: We will just go around the table so that we will know who is represented, and then we will go back to the remarks.

MR. BARMACK: Hi, I am Matt Barmack. I am the Director of Market and Regulatory Analysis at Calpine. Calpine is a large owner of relatively new combined cycles and combustion turbines in California. We do not have once-through cooling issues, but we are very active in wholesale markets here.

MR. BAKER: Thank you.

MR. VAWTER: I am Don Vawter. I am Director of Asset Management for AES Southland. In the L.A. Basin, we own 14 units all on once-through cooling for a total of approximately 4,300 Megawatts.

MR. BAKER: Thank you.

MR. MOHTASHAMI: I am Vafa Mohtashami with RRI Energy. We own roughly 2,000 Megawatts that use once-through cooling primarily in the Big Creek Ventura area. I am the Director of Commercial Operations for our West Region, which includes all of our plants in the ISO control grid.

MR. BAKER: Thank you.

MR. DAVIE: Doug Davie with Wellhead Electric, Vice President with Development of Regulatory and Business Asset Management, probably one of the very small class of truly independent owner operator -- developer/owner/operator of power plants. We do not have any once-through cooling. We are primarily focused on peaking facilities right now in the San Joaquin Valley, but are developing plants in San Diego and SoCal's territorial zone.

MR. BAKER: Thank you.

MR. MITCHELL: Good morning. Will Mitchell, Competitive Power Ventures. We are the developer of the CPD Sentinel Project which is one of the three projects that has a Southern California Edison power purchase agreement, but has been delayed due to the ongoing party reserve issues, which has given us a unique opportunity to get involved in the greater umbrella of activities that incorporates Southern California's electrical future.

MR. BAKER: Thank you.

MR. FREDERICKS: Uh, Dale Fredericks, Manager of DG Power, a private developer. We have developed a total of about 650 Megawatts of new generation in California in the last years, none of them utilize once-through cooling, they are all [inaudible] [17:16] style power plants. And, as a private developer, unlike the other panelists, I handle the development permitting and financing of projects with resort to private capital markets.

MR. BAKER: Thank you. So, with that, because of the full agenda today, what I have done is I have asked the panelists to keep their remarks to about five to seven minutes. And in order to facilitate that process, I have asked them to focus on specific questions in advance, but I would like to take the panelists in order, roughly in order, that it makes the most sense. So we are going to jump around a little bit and not just go around the table. I encourage the panelists to engage each other, as well, to foster productive dialogue on these issues. To begin with, I will however, just to sort of set the stage, go ahead and read through the questions.

The first is, can OTC replacement be done via the IOUs RFO process; secondly, how should an RFO be structured? What changes are needed from the current process to facilitate competition between possible green field sites, building new units on existing sites and repower to replace cooling systems? How should RFO products be targeted to a particular location or product type? Fourth question, do the current markets provide adequate sense to design plants to provide ancillary services regulation to integrate renewables in its system? Fifth question, what length of contract would be optimal?

And the sixth question, how to repower via AB 1576 be conducted or approved and completed? I have asked all panelists to provide an answer to the fifth question, which is a rather quick question, and I will be beginning, however, with Dale Fredericks from DG Power, and I have asked him to focus on question 1, 2 and 5. Is that correct? I believe it is.

MR. FREDERICKS: Thank you.

MR. BAKER: Thank you.

MR. FREDERICKS: I believe question 1 is clearly, the answer is yes.

COMMISSIONER BYRON: You know, if you gentlemen are going to refer to question numbers, I do not think the rest of us have the benefit of knowing these questions. Do we have them on the screen, by chance? Or is there any way -- otherwise, you are going to have to refer to them periodically, simply remind us, okay?

MR. BAKER: I am asking Dale to focus on Question 2, which is how should an RFO be structured, and what changes are needed from the current process to facilitate competition within possible green field sites building new units on existing sites and repowers that replace cooling systems. I have also asked him to speak to the optimal length of contract. And I will be following with Don Vawter to speak to the same questions, 2 and 5, and also question 6 on AB 1576.

MR. FREDERICKS: Again, the first question is whether OTC replacement can be accomplished through the IOUs RFO process, I think it can. But in my view, the RFO process needs to be made more specific with respect to OTC issues. And they do vary significantly, one to another. There are projects in Northern California that are very different from those in Southern California, I think they require a different approach. So it strikes me that a consideration at least should be given to approaching this in the procurement process in two phases, the first phase would be to address the projects in a grouping, or regional, or other logical basis where there are some that ought to be considered separate from others. I think the IOUs can and should issue special requests for offers for these tasks and should be narrowly targeted, as was suggested earlier because each one involves very specific issues and concerns. A general approach is probably not going to be successful. In conducting RFOs, it also seems to me that a strong preference ought to be given to projects that would replace the existing units because they are old and inefficient, as well as environmentally at issue. And full environmental remediation of those old sites ought to be made a part of the process, preference ought to be given to use of reclaimed water, as opposed to ocean water or other fresh water sources. Air cool condensers may be appropriate in some locales, not others; it depends on the particular situation, but air cooling, if reasonably practical, can be a very useful alternative to wet cooling technologies. These preferences ought to be given also to highly efficient, new technologies. And by that, I am thinking of the focus on system that are combined cycle with low heat rate, low emissions, low water use, and units that possess flexibility to meet the realities of the renewable portfolio standards. And that is some sort of ramping capabilities, low emissions on start-up and shutdown. There are technologies that have emerged rapidly that already, we know, meet some of those criteria. Just a few years ago, GE introduced their new LMS100 that was a major improvement over the prior LM6000 peaking unit, about a thousand point heat rate advantage and much lower emissions. And in the last year, Siemens has introduced something called a Flex Plant 10, which is a combined cycle, highly flexible unit, that is even better, it has yet another thousand point heat rate improvement at a fraction of the emissions, and a fraction of the water use of the LMS100, it is a highly flexible unit that has the ramping capabilities to support the renewables. Those and other new technologies that some of us have already gotten a glimpse of, from General Electric, Siemens, Mitsubishi, see now that this is a trend, and I think California should lead in encouraging replacement generation to be the most efficient available.

MR. BAKER: Mr. Fredericks, before we move on to our next panelist, if I could just ask a more probing question. It is my understanding DG Power does not own any of the existing OTC plants, so in the hypothetical, if a narrowly targeted -- if the utilities were to issue, say, Edison were to issue a narrowly target to RFO, to replace generation in the local area, or sub-area, in which Alamitos is located, would you see that RFO structure as being sufficiently competitive that your company could compete?

MR. FREDERICKS: Probably not because, obviously, the owners of those plants have that stacked in their favor, but that is not necessarily a bad thing in this context, but the RFO could be focused on the replacement of the existing OTC plant in a very organized fashion and allow those firms to come forward with a proposal, hopefully along the lines of the criteria just outlined, and then allow that to be evaluated -- is that a proposal that ought to be accepted under what I am going to suggest would meet the long-term CPA, say 20 years or more, to help reduce the cost to the ratepayers. Is that an attractive proposal compared to all of the other options that could be evaluated? And in that process, I am thinking that it would be useful to further modify the RFO rules to allow, in addition to the procurement review group, and the independent evaluator for the site, to include representatives of the PUC, the Energy Commission, and the Water Board, to help provide input in evaluating those proposals, to decide is this one we should accept? Is it just and reasonable? Or is it one that simply should be rejected with the ultimate result in that plant closing down over time?

MR. BAKER: Thank you, Mr. Fredericks.

COMMISSIONER BOHN: May I ask just a -- noticeably missing was any consideration of cost.

MR. FREDERICKS: Cost is going to play into the bids that you would see from all of the owners of once-through plants. They would propose in this RFO to replace them with something else. And if the cost is too high, I would think that the answer would be it is too expensive, we are going to reject that proposal, this plant should be shut down. And then, my second suggestion is that there could be a follow-up RFO that would consider green field sites. And in addition to the plants that are going to be replaced with the new technology.

COMMISSIONER BOHN: So you do that in sequence, as opposed to an RFO that simply asks for a solution?

MR. FREDERICKS: I would think so, because, again, private capital is not likely to step up and bid in a program where the deck is stacked in favor of the owners of existing plants.

COMMISSIONER BYRON: I would ask that you speak right into the microphone because I am not sure everybody heard the tail end of your last comment.

MR. FREDERICKS: The view, I think, of a number of private developers is that it is unlikely that we would bid and could attract private capital to bid into an RFO that was running up against the owners of existing OTC plants that were in that process, proposing to somehow replace them. They have too much information. They already own the site, they have the infrastructure in place, or most of it, such as transmission, that it would be very difficult for a private developer in a green field site to come up with a more favorable proposal.

MR. BAKER: Thank you, Mr. Fredericks. And with that, I would like to move on to our second panelist, Don Vawter from AES. And I imagine that you may have a counterpoint to some of the suggestions we just heard from Mr. Fredericks. I would ask you to please focus on question 2 and question 5 on contract length, and also question 6 regarding how AB 1576, repowering could be conducted. Thank you.

MR. VAWTER: Thank you. Thank you for allowing me to be here and give you my fair and balanced view of these questions. I think that an effective number of our units could be repowered in an RFO that is not specific to OTC plants, given if there are two things done, in particular. One is to fairly evaluate our local reliability attributes as compared to other plants that are technically in the same local reliability area, but given equal weighting to our OTC plant. Not all LCR assets are created equal. The OTC plants are in the heart of the load, generally be definition. Additionally, we see a lot of exceptional dispatches that reaffirm the point that there are local reliability attributes associated with our assets that are not being fully contemplated in the RFOs. There is a division between procurement and transmission in the IOUs, and we think that it is a barrier to fully appreciating the attributes or assets. Additionally, any RFO should be adaptive in its need. If it is, for example, an RFO for 2,000 Megawatts, and I am retiring a 1,000 Megawatt unit and repowering with a 1,000 Megawatt unit, I am not incrementally closed, or the need identified by the RFO, and that should be taken into account, clearly. In that way, assets such as ours could effectively compete in an open RFO with green fields. What certainly cannot happen is that OTC units be discriminated against if they are bidding into a repower RFO where the fact that they are not closing the gap on the RFO need is held against them.

MR. BAKER: Mr. Vawter, are you aware that, in the Commission's procurement decisions, when new authorizations are made for the utilities to procure, that there is a certain amount of retirement assumptions that are embedded in that analysis? And that, in the most recent LTPP decision, it was a great deal of retirements were assumed, and so, to your second point, I believe that that issue is addressed, that repowers of existing facilities are eligible to bid.

MR. VAWTER: Yeah, they certainly are. And in the LTTP, Long-Term Procurement Plan, there are scheduled retirements, however, those are at best assumptions, right? Because they do not have commitments from any other generation owners to retire those assets, so they have a Megawatt value plugged in, as coming out of their mix due to a retirement, and that goes into calculating what the RFO needs. But that needs to be hanging with a big asterisk, again, and when an asset such as ours bids into the RFO, and it is coupled with retirement, then the overall need identified in that RFO needs to be adjusted accordingly.

MR. BAKER: Did you have any comment on a contract length or on the AB 1576 question?

MR. VAWTER: Regarding PPA length, you know, the longer the PPA the better the financing, the better the financing, the lower the rates, you know, that is true in any financing, whether it be your house or a power plant. You know, the longer the better that is for everybody involved. Regarding 1576, we would be interested and open to an open-book negotiation at cost replacement of those assets over time, the devil is in the details. You know, I would like to just add a couple of things. Market heat rate in Q3 is greater than the oldest, most inefficient assets we have, you know, our oldest most inefficient assets have been running all month. We expect them to run, you know, most of August and most of September, as well. Despite that, you know, we do not participate in the real time markets, but the real time markets had intervals last week that cleared at greater than $500. The week before, intervals greater than $700. We cannot necessarily demand side manage and transmission upgrade our way out of this problem; these plants need to be replaced over a considerable time. And with that, I will end. Thank you.

MR. BAKER: Thank you, Mr. Vawter. With that, I will turn to Doug Davies of Wellhead. And if I could ask you, Mr. Davies, to please focus your remarks on question 3, how should RFO products be targeted through a particular location or product type, and question 5 on contract length.

MR. DAVIES: Thank you. Again, thank you to the various energy agencies for this forum to talk about this, very timely and of critical importance. In terms of looking at RFO's and trying to target for a particular product --

COMMISSIONER BYRON: Mr. Davies, go ahead and put the microphone right out to --

MR. DAVIES: For a particular product, a particular location, just from a cost standpoint, I think you want to be extremely careful about specifying constraints, conditions, limitations, because all you are going to do in a competitive market is add constraints and limitations, you are going to drive costs up. So as you look at the need for replacement of once-through cooling resources, you need to look very carefully at how much do I really need to replace, or does it really need to be, you know, does it really need to be at load center, is that a location where I really have to have the generation? Is that the amount of generation I need to have at that location? And set your requirements up front based on some very solid basis, stick with it. Clarity, communication and follow-through on what you are doing and why you are doing, is critical to the market if we are going to respond with our creative, innovative ideas, and provide options and alternatives for you to consider. So leave it as open as possible, limit the constraints, because you are simply going to make it more expensive, tougher for developers to respond. In terms of responding to the replacement to a once-through cooling plant, Wellhead does not have any once-through cooling plants. Would we look at opportunities and would we propose developments in response to an RFO? Absolutely. We are going to look at what the opportunities are and we are going to look at what the requirements are, what the RFO wants, what the utility wants, and we are going to decide can we -- do we think we could compete in that arena? A once-through cooling plant may not need 1,000 Megawatts in the same place, maybe it needs 500 and the other 500 could come from someplace else. Does it need to be at that same location? Maybe not, maybe so. Communicate that to us. From a length of contract standpoint, I would absolutely echo what Mr. Vawter said in terms of the longer, the better, but I also realize the utilities need to have a portfolio that is a balance of short and mid and long-term resources. But you cannot eliminate, if you want to have the lowest possible prices, you cannot eliminate long-term contracts, 20 or 30-year contracts, that is what utility rate making provides. You do not want a single set of options, utility-owned generation that has 30-year financing benefits to the ratepayers. Let the market also provide that same benefit of long-term financing to the market, to the ratepayers. Getting the markets right is critical also, unless you want to add that, in terms of when you have a contract, or you are delivering your resources, you are looking at markets -- how you are being dispatched, how you are being operated, references to many exceptional dispatches. Developers and generators and owners are looking at how the markets are working, whether it is for local capacity -- are you being called upon in a particular area more or less? Is the market working correctly and properly? So that is a critical element to the RFO process, that being selected is one thing, you are then subject to being an operator and what are the conditions of your contract, and how are you being paid? Is it a pure RA contract? Is it a long-term [inaudible] [38:54] contract? There are various contracts that are there, so there are a number of elements of the market that have to be pulled together to think about it from a development standpoint, what am I going to propose? How am I going to be compensated? You will have confidence that I will get paid and will be able to make a return on my investment. Same exact question a utility asks any time they want to build something and they go for a CPCM, they want to know -- investors want to know they have a return potential and they can manage the risks that are there. One last comment I wanted to make, and it is not specifically on here, but I think it is of critical importance to the energy agencies to understand, is that once the decision has been made that a particular resource is, in fact, desired and needed, there needs to be support from the energy agencies, from the CAISO, from the utilities, from the Utilities Commission. Particularly in our case, we look at a lot of local permitting. We end up, in many cases, with a lot of local opposition. We have no support because the public agencies do not like to support specific projects. They will say yes, the resource is needed, but in the venues where we are doing permitting, the only voices that are frequently heard are by the local opposition, the "not in my backyard" people, and if we are going to solve the problem, have the resources come on line and get permitted, small resources under 50 Megawatts that are not CEC jurisdictional, as well as large, the energy agencies need to be proactive in supporting the resources that have been selected by the utilities to go forward. I will stop at that point.

MR. BAKER: Thank you, Mr. Davies. I will also make one additional -- share an additional piece of information, which I neglected to mention in my procurement rules presentation, pertaining to the contract length, under current procurement rules, the eligibility for CAM treatment, the Cost Allocation Mechanism, is limited to the term of contract of 10 years, and so we will be hearing from some of the panelists that contract lengths of up to 20 years may be preferred from a cost perspective, so that is relevant in terms of how changes might be considered, going forward. With that, I will be turning now to Will Mitchell from CPV. And I would like to ask you, Will, to focus on question 3, how should RFO project products be targeted to a particular location or product type? And also contract length.

MR. MITCHELL: Thank you. Good morning, Commissioners and staff. Commissioner Mansour, as you recall, the recent CAISO Forum participants who praised your work were given additional time to speak, I must say what good work and praise your organization zealously. You are looking at a brief opportunity to contextualize here.

MR. MANSOUR: I am going to leave now.

COMMISSIONER BYRON: Mr. Mitchell, I would like to remind you, you are at the Energy Commission today.

MR. MITCHELL: Yes, I apologize.

COMMISSIONER BOHN: Yes, we welcome you at the PUC, [inaudible] [42:10] efforts down there.

MR. MITCHELL: As I mentioned in my brief comments, Competitive Power Ventures, we are the company behind the

Sentinel project in Southern California, which has had an opportunity to observe the many elements that have come under increasing consideration in this evolution of the California regulatory arena. In light of these observations and the CPUC's recently released LTTP straw proposal, we believe it is important to recognize the energy agency OTC Report, which brought us here today, among other factors, within the greater planning context. Currently, CPV does not manage any power generation in California, they do utilize once-through cooling. But as a developer of green field gas-fired projects like the Sentinel project, which is capable of serving as a replacement capacity for generation that does utilize OTC, we look at this report, as well as the greater umbrella of the proposed LTTP, as a step in the right direction in providing improved regulatory certainty for industry investment, as DG's and other folks have mentioned, as well as environmental objectives, which have become an increasingly large part of the process. As the report states, Southern California has the largest concentration of facilities that utilize once-through cooling, but given the number of barriers, as we all know, most of which have come to a boiling point over the last 12 months, the development of cleaner and more efficient generation has been substantially delayed. The genesis of that and a number of other factors have made it apparent that the regulatory and planning process by which we develop power plants needs to be adjusted. With that, the inter-agency collaboration, as Will had said, which is sometimes not there, the inter-agency collaboration that came together for the once-through cooling report should serve as the precedent for directly addressing the remaining barriers, which are inter-dependent upon effective OTC policy, particularly in Southern California. It was an incredibly useful report and to have the three agencies together. The proposed power plant infrastructure plan that they touched on, as explained in the reports, heads in an interesting, and in our opinion, beneficial direction. The Commissioners made it clear there is a fine line between spending resources to improve system planning, but the specifics, which are being discussed today, intends to substantially reduce the regulatory uncertainty and also, at the same time, conciliate a growing opposition movement, which is why we have extensively, on behalf of improved system planning, it really works in a direction that is good for investment, as well as the development sector. So in our opinion, we look forward to more inter-agency collaboration, especially panels like this with the ISO and the CPUC and the EC's are here. Now, to answer the more specific question that the CPUC asked, another recent report in the MRW Report touched on the future of gas-fired generation in California, and identified five primary roles -- intermittent support, general energy support, replacing old infrastructure -- those types of classifications could be very beneficial in being utilized in the upcoming RFO's when identifying specific resources in specific regions. Developers can develop any product that is needed, and the more certainty at times, the more certainty that is given on what is needed, we can create the most specific package, it is what we are here to do. And I can continue on the contracts, if you would like.

MR. BAKER: That would be great, thanks.

MR. MITCHELL: Sure. As others have said, long-term contracts are always beneficial for a number of reasons, but by far they are the most beneficial for ratepayers. As costs continue to come up, nothing saves the ratepayer more money and lowers the over-regulatory cost than a long-term contract. And there are numerous studies, some of which focus specifically on competitive procurement. The Maryland Public Utilities Commission recently commissioned a study which focused entirely on the competitive procurement aspect of long-term contracts, and it showed that, over a period of time, they appeared to save billions of dollars. And with that, we have found that investors are becoming increasingly concerned with the

10-year contract terms in California, and with today's distressed financial markets, 20-25 year contracts are far more likely to be followed by private investment, which is what the state needs. Thank you.

MR. BAKER: Thank you very much, Mr. Mitchell. Now, I will turn to Vafa Mohtashami with RRI Energy. And I would like to ask you to just focus on question 4 and 5 on contract lengths. Question 4 is, "Do current markets provide adequate incentives to design plants to provide ancillary services, for example, regulation, to integrate renewables into the system?"

MR. MOHTASHAMI: First of all, I would like to thank the Commission and the overall agencies for the opportunity to present RRI's perspective on the once-through cooling rulings before us.

COMMISSIONER BYRON: Please pull the microphone closer to you and everybody in the room will be able to hear you better.

MR. MOHTASHAMI: Okay. With respect to the current market structure, the short answer is, yes, the current market can provide the price signals to direct new build or existing assets for the ancillary services that are currently defined as products within the ISO. However, given the number of out-of-market commitments and acceptable dispatches that our plant has seen over the last few years, it does seem to indicate that there are services that our assets are providing. They are not formally identified products. And so, I think it is incumbent upon the ISO to go through an assessment of what products it needs to reliably operate the grid and integrate renewables into the portfolio. For example, the ISO is currently contemplating a 30-minute product as an ancillary service. So I think having an honest assessment of the needs is paramount to the implementation of this policy. Additionally, it appears that there are location-specific services that these once-through cooling generation units provide, as mentioned before, that needs to be assessed in determining the scope and the sub-regions by which these ancillary services are here. So, acknowledging the need and the nature of these services, both on a grid-wide basis and a location-specific basis, I think it is paramount to ensure that the equivalent reliability standard is met as we look to comply with the rule.

MR. BAKER: Do you have a comment on the contract length?

MR. MOHTASHAMI: Yes, I do. So, given the ancillary service and acknowledging that there is a need for probably a broader scope in ancillary services, and then tying it back to the contract length, we are advocates of a centralized capacity market, and we think that the proposal that we have put forth under the CFCMA contemplates a 10-year lock-in price period based on the clearing price of the option for the planning enterprise. But in parting, you know, I would like to bring up some other points, as well. We have focused on the Air Quality District permitting issues and those are real, but there are also local constraints in terms of permitting new facilities, namely the issues that SCE ran into with permitting the McGrath peaker and the City of Ventura where Ventura County had a problem with incremental industrial development. So I think, you know, we probably need to be more holistic in assessing what other permitting hurdles are out there as we seek to eliminate the reliance on once-through cooling and comply with the rule.

MR. BAKER: Thank you. Next, I would like to hear from Matthew Barmack of Calpine, and I would like to ask you to focus your comments on question 1, can OTC replacement be done via the IOU's RFO process, kind of wrap-up, and question 5 on contract length. And also, if you have any comments on the AB 1576 question, as well.

MR. BARMACK: Okay. I will take a stab at that. With respect to Question 1, I interpret this question a little bit more generally. I interpret it as asking is competitive procurement to replace OTC units feasible. I think my comments will echo a lot of the things you have already heard. If there is competition, you can have competitive procurement and the way you get competition is defining the requirements or replacement is generally as possible, you know, potentially include both new and existing units in the procurement, and you can put units at multiple locations, so just echoing some of the comments of my fellow panelists. I would like to pick up on one thing that I think I heard Don say, which is, it is unclear that the utilities have the appropriate price signals and the appropriate analytic tools to differentiate between different projects with different locational attributes and different operating characteristics, and so that is probably one aspect of the current procurement process that will have to change. The analytic tools that are used in the IOU's, RFO's, will have to become more sophisticated.

MR. BAKER: And could you provide any specific examples in that regard?

MR. BARMACK: You know, I would like to keep my comments at a relatively high level, but based on one utility's procurement process, my sense is that, in that process, location and operating flexibility are kind of subjective factors, and it is really unclear how that utility makes trade-offs between projects which are all attractive, but have slightly different bundles of locational characteristics and operating characteristics. Thank you.

COMMISSIONER BYRON: And what are those characteristics we are talking about?

MR. BARMACK: Well, location is location, but then operating characteristics would include things like ramp rates and the ability to provide regulation, for example.

COMMISSIONER BYRON: Thank you. That is general enough.

MR. BARMACK: Okay.

MR. BAKER: And did you have anything on AB 1576?

MR. BARMACK: Did you ask about contract term?

MR. BAKER: And that, as well.

MR. BARMACK: Why don't I speak to that. I think I have a somewhat different view than what I have heard up here. I mean, first of all, I would like to differentiate between existing assets and new assets. You know, I think one under-appreciated fact is that there is a lot of latent flexibility in the existing fleet, and if you pay guys, the flexibility will be forthcoming. And you do not need long-term contracts to do that, you need many of the things that the ISO is already pursuing like, you know, scarcity pricing and potentially some additional ancillary services, and higher big caps and higher price caps. So I think we are moving in the right direction and I think we will be surprised about how much flexibility the existing fleet can provide. With respect to new build, you know, nothing in California gets built without a long-term contract with an IOU. As I alluded to, I have a somewhat contrary view about contract length. I think it is true that, you know, the price to ratepayers, measured very narrowly, is lower with very long-term contracts, but what that does not recognize is, through committing to long-term contracts, utilities and their customers are assuming a risk. And there is a trade-off there, I just wanted to indicate that there is a trade-off that does not cut all in one direction.

MR. BAKER: Thank you, Mr. Barmack. With that, we will move to Alan Comnes, and you will have the final word of the panelists. I would like you to focus your comments again on Question 1, can OTC replacement be done via the IOU's RFO process, hear your comment on contract length, and also hear about AB 1576.

MR. COMNES: Thank you. I just wanted to add that since I go last, I get all the remaining time --

COMMISSIONER BYRON: However, there is none, so please go quickly.

MR. COMNES: Okay. Can the existing RFO process work to accommodate once-through cooling replacement? NRC would say yes, but…. And there are some important "buts" here, it is going to take you longer, and it is going to cost you a lot of money, I think you have heard that, and it is going to take you longer, and if you want to succeed, you need to be flexible along the way. You need to be able to define success pretty generally so that you can get there eventually. So what do I mean by more flexibility? And it is something that I have not really heard raised today. But, first is, you know, NRG does own once-through cooling units and, of course, we have repowered units, we have contracts to repower units, and we want to bid more peak days into repowering units, but we understand that there is an importance in competition and so, the way to do that is you have to have a very well-defined set of market requirements on what is acceptable replacement generation. And I really think that comes to -- it is a two-fold requirement, one is the market has really got to signal what kind of products they are going to want in the future, and I think Matt alluded to that, but we really need some clear signals in terms of regional ancillary service requirements, making the sort of hidden reliability requirements that are not well understood like, say, SCIT, well communicated, you know, we need new products, we need a 30-minute reserve, we need it for reserve markets. So those things will help to set a market signal. Second, we need a very well-defined LCR study. There is talk about a

10-year LCR. I would venture a guess that is going to take a little bit more work on a spreadsheet in that that information needs to be communicated very clearly in an advance CRFO so that you can actually get generation that meets your needs. Second, flexibility in the actual procurement process; we have been through a few BPA's with these utilities, it is a -- we like the bid-based system, but again, you are going to need even more flexibility to meet this additional requirement of once-through cooling retirement. So the things that we see that could be reformed or modified, the PPAs, include allowing the sufficient time in change of law provisions to respond -- to bounce along the way in terms of getting PUC approval and necessary permits. We all have this going on, for example, with the South Coast Air Credits. We need reasonable credit and collateral provisions; there are some pretty onerous requirements out there by some of the load serving entities that are procuring, it is obviously a natural protection on the part of the buyer to want a credit-worthy counterparty, but on the other hand, you are going to severely limit competition with some of the requirements that are out there. Third, you do not want to have punitive penalties in the contracts for certain operational characteristics. We have heard time and time again that you are going to need certain operational characteristics to accommodate renewables, and some of the attributes that once-through cooling units have traditionally provided. Just to give you an example, you know, the LMS100, it is now somewhat established, it has been built, but I would venture to guess that if, in the current credit market, if the LMS100 came along today, it would be very hard to finance. So think about that. There are new technologies coming. The gentleman from DG mentioned some of them. We are proponents of them, but you have got to build contracts that can accommodate the new technologies and actually be financeable. I know this is not really the crowd to get into these details, but where this comes into, the process that I have heard is, that Simon talked about, as part of the RFO process, he needs to review the RFO documents and the pro forma, and that is where I think the Commission staff really needs to take a careful look, again, if they want to succeed. Another area in terms of flexibility is -- or, I am sorry -- in terms of making the procurement process work to meet once-through cooling objectives, is a solution that is hidden in plain sight, you know, I will not even call it the elephant in the room, I will call it the pony in the room, it is the capacity market. The gentleman from RRI mentioned it. Right now, my existing assets earn one-quarter to one-third the price that new units earn; if you want to figure out a way to get existing units to accommodate to any sort of medium-term to more possible retrofits that actually might meet once-through cooling or sort of the 316B requirements, a capacity market is a way to do that. A capacity market could also handle new generation, as the gentleman from RRI mentioned. And all those attributes I talked about, contract flexibility, or PPA attributes, can be built into the tariff design of the capacity market, so they are not mutually exclusive. I will move on, yes, about contract length. NRG is not doctrinaire about contracts. We have built repowered generation on 10-year contracts, again, with the capacity market, we think that can support new generation with a 10-year strip built on the end, or really, when we say that a longer-term contract provides better ratepayer benefits, that is true if you have sort of the market structure that is sort of a gotcha at the end, where once your contract ends, you again once get $.25 on the dollar in terms of what the capacity is worth. So if you have a market structure that has capacity market, then you will actually see the better prices with shorter tenure deals. That said, given the current market environment, if you want to have a lot of obligations and you are trying to manage costs, so you are probably going to get a wider range of prices if you allow for longer tenure deals. One final thing I will say about the longer tenure deals, it is not only the LSE's consider the CAM to be the requirement, some of the LSE's are entering the 20-year deals, they do not seem to be concerned about -- or they are willing to take on the risk of cost recovery past year 10. So I think you can also ask questions of the LSE panel about whether they are willing to enter into longer dated contracts. You asked about 1576.

MR. BAKER: Yes, I did.

MR. COMNES: Okay, well, the last long-term procurement proceeding had an extensive record on 1576. There was detailed proposals provided by both the utilities and generators. And yet all that came from it was, I would say, a strengthening of the rebuttable presumption language that is in the LTTP order, namely that the Commission should -- or, sorry -- utilities and their RFOs should go to great lengths to try to procure sites that utilize ground fuel and also lead to the retirement of once-through cooled facilities. However, there was no adoption of any of the cost-based proposals from the point of view of the generators, and some of the utility proposals were pretty onerous, they essentially required us to hand over the asset at the end of the contract term, which is not really our business model. So I guess my suggestion is, you know, we support AB 1576, we understand it, and one of the reasons for it was to try to achieve the state's objectives with regards to 316B to have requirements, but I would suggest maybe that the Commission or its staff, actually, come up with a proposal and actually drive this, rather than ask for a lot of proposals and then not really take them to completion, which is what happened the last Long-Term Procurement Planning Proceeding.

MR. BAKER: Thank you, Mr. Comnes.

MR. COMNES: Did I use my time?

MR. BAKER: Yes. We do have a few minutes remaining if there are any questions from the dais.

COMMISSIONER BYRON: Absolutely, there are. Mr. Mansour, did you have some questions?

MR. MANSOUR: There are a couple on that opportunity and get some free consulting from this very powerful panel, so first of all, I agree virtually with just about everything you said in terms of identifying what the issues are, and how we may go about -- but this is going to get into the next level of detail, two details about the fact and get some ideas, and more specific. And if it is not today, maybe some other time, so in one of the other forums. On the planning side, a number of you said we need to read now well in advance what the requirements are so we can respond to it. So we move from an annual process, which was the ISO's, and the PUC's results and adequacy to combine -- to align the two, and came with the local capacity requirement, which really took care of most of what used to be at [inaudible], and had it in the procurement process to do what the results adequacy to consider locational stuff. Now -- and that was spelled year by year; now you saw the proposal that we will do multi-year, a 10-year advance of locational capacity requirement, and we will do that open and it will be published and, you know, as a planning protocol of the ISO, or even under 890 for the whole state. Anything else that you can think of that, you know, you are looking for? Or that will do it? That is my first question. I have another question if we have time.

MR. BAKER: Anybody want to address that?

MR. BARMACK: I have one comment on that.

MR. BAKER: Go ahead.

MR. BARMACK: I mean, I think from the ISO's standpoint, that is a lot of what we need, but I think what is still lacking in California, which some other markets have, is some link between these planning activities and procurement. So I think, if you go ahead with what you just described, and the PUC sort of closes the loop, then we will have everything that we need.

MR. MANSOUR: Anyone else? Anything else?

MR. MITCHELL: From a capacity market standpoint, which RRI and NRG both touched on, we are of the opinion from experience and other ISO's that a centralizing capacity market is not necessarily green field generation. You take ISO New England, for example, they have got a large -- thousands of over-generation that puts them up in a 2017, and one could argue that ISO New England is over-filled, but there are also clearing and existing capacity old gas capacity and coal capacity and products that use once-through cooling, and there is not a venue or a system to incent green field to come on there. So what perhaps, as this process at capacity market builds and ebbs and flows here in California, a bifurcated capacity market may need to be looked at as a viable argument to incent existing and green field if we want to bring on new generation to improve the system as a whole.

MR. MANSOUR: Well, you actually got me to the second question that was, how many of you -- or, would any of you -- agree that, if we have a capacity market and ancillary service market, you would be able to finance [inaudible] [69:07]?

MR. DAVIES: One thing that is absolutely critical on that is confidence and if those markets are put in place, they will be there and they will remain there for the long-term. And right now, I do not think California has a history of putting things in place that stay there long enough to give investors confidence that they will remain and they will, in fact, go with the time frame they anticipated, earn the returns, or get even fair returns back, much less --

MR. MANSOUR: Maybe some one will tell me a place that actually have that, instead of do I have it, but just with all of what you know and what you do not know, like realities in terms of, you know, the regulators can change things and it is not disturbing that that is their intention, but from time to time, there might be a change, a crisis happened in 2000, and it will require some change; you cannot expect regulators -- look at what is happening in the financial market, one is off until it crashes and, so, "My gosh, how come we did not fear early on?" So it is -- with all the realities that you know, do you think that if we had a capacity market and an ancillary service market, and on that subject, as you wish, would you be able to have the right capital to invest in new green field?

MR. DAVIES: I think that was my point, Yakout, is that, without the certainty, it is going to be very difficult to get investors on new green field major projects, and therefore, even markets as has been discussed, may be more well suited for existing generation and market that comes into play at the end of a 10, 15, 20-year contract, as compared to a structure that is going to facilitate or allow green field investment.

MR. MANSOUR: Anyone else?

MR. COMNES: I, well, first of all, it is going to take a while to pass more of the grounds early [71:00] and, given the pretty ambitious schedule that is laid out in the energy agencies' paper, you are going to need one or two rounds of RO's in addition to getting the RFO that has already been done out of the ditch done. But eventually, to answer your question, yes, I think there is evidence in PJM that, you know, a capacity market supported new generation.

MR. PETERS: I think capacity market, newly established, would not be financeable, you could not finance a new green field project. It would take some time, and therefore, at minimum, it ought to be phased in. I think the long term PPA is the solution because that, for example, allows a full range of competition. The PUC has indicated in its rulings that it wants to promote competition for new generation. Well, exactly what does that mean? Private firms such as ours that want to bid into an RFO will look at competition against utility-owned generation, and competition from other established water [inaudible] [72:13] who have a longer term horizon than maybe some of the financial markets, and therefore, if you are going to have a broad range of competition available, and encourage that, you need to encourage the type of competition that allows new interests such as our firm has brought in on some of these projects, so that if they have the confidence that they can come in, offer a competitive bid, and know that they have a long-term, say, 20-year or so, contract to support it, that allows them to offer a much lower price because they do not have to be so concerned about residual value, and debt service coverage ratios that are ever changing in a volatile capital marketplace. That provides long-term stability and encourages a broader range of competition.

MR. MANSOUR: So, Commissioner, actually my question is, even though it may sound like it, are we off track or not, like on the eighth OTC we are talking about, do we focus on the mechanism that exists to repower? Or do what is necessary what can be done in the existing plant? Or offer competition of replacement to green fields to actually ban one and move with the others? I am trying to think of what mechanism we shall have, other than what we already have, that would make that at least that competition between the two, [inaudible] [73:30] as possible.

COMMISSIONER BYRON: Uh, Simon, you said you had some closing remarks on this panel and we are a little bit behind schedule, so --

MR. BAKER: I actually was referring to Mr. Comnes. He played wrap-up.

COMMISSIONER BYRON: Okay, well, I would like to thank you all very much. I mean, we could go on for another hour or two. I think it is also worthwhile just mentioning maybe the obvious to you all; first of all, there are so many acronyms, I apologize to those in the audience that are not familiar with all the acronyms that we use in this panel. I started writing them down when you were speaking and you had eight of them by yourself, so --

MR. COMNES: I will post a glossary.

COMMISSIONER BYRON: But this is all about the procurement process and this input is extremely valuable, but I would remind everyone that this just addresses really the investor-owned utilities procurement process, we also have a number of once-through cooling plants that are in the public-owned utility domain. These gentlemen all participate in that process and it is rather complicated. I have a feeling, Mr. Baker, it is going to get more complicated. I appreciate your openness to listening to all this input. We are not going to make your job any easier. But this is very good input. We are going to take a break now until 1:15, just checking by the clock in the back of the room, which is different than other clocks. So I would like to thank you all and hope you will return. We have got a packed afternoon. Again, our panelists, thank you.

[Off the record at 12:07 p.m.]

[Back on the record at 1:19 p.m.]

Agenda Item 5: Panel 2: Changes to Procurement from an LCE/IOU/Consumer Point of View

MS. KOROSEC: All right, let's go ahead and we will begin with our second panel, which is going to be moderated by David Vidaver from the CEC staff. David.

MR. VIDAVER: Thank you, Suzanne. For the record, my name is David Vidaver, V-i-d-a-v-e-r, and I am with the California Energy Commission's Electricity Analysis Office. As far as this process goes, a true lynch pin of successfully eliminating OTC is the CPUC procurement process. Long-Term contracts for new capacity or to pay for capital investments to rethink existing facilities, are needed in order to secure financing. There has been only one major facility that was permitted by the CEC since 2001 that has come on line without a long-term contract. The goal of this process is an RFO, or more correctly three, or four, or five, where minimal amounts of gas-fired capacity are solicited in order to meet local and system reliability needs and the other policy goals of the state. And to do so, in a least cost fashion, in RFO's that are more competitive, drawing as many green field, brown field, and perhaps even refits, as possible.

This panel is being asked to discuss the implications of the Joint Energy Agency Proposal for the procurement process, from the single and unique perspective of the utility ratepayer environmental community. I hope this discussion involves everybody. Although many slides are being somewhat utility centric, I encourage all and other panelists to interject when they have something to say, and I will probably bushwhack Mr. White with a question or two at the outset in order to make sure his concerns are fully captured. Rob Anderson, the representative from San Diego Gas & Electric, sits on my far left; we have Kevin Cini from Southern California Edison; Marino Monardi from PG&E; Matthew Tisdale from Department of Ratepayer Advocates at the CPUC; the Honorable Mike Florio, representing TURN; and V. John White with CEERT. We hope to have a representative from LADWP online, at the moment he is not here, I have no comment about that.

COMMISSIONER BYRON: Mr. Vidaver, just because this is an AFZ, and Acronym Free Zone, you called it CEERT, which is making a word out of an acronym, let's give it -- let's work on helping everyone understand what all these things are.

MR. VIDAVER: Oh, Lord, Con - something for

Emergency Renewable Efficient Renewable Technology -- I am sorry, perhaps Mr. White would like to --

MR. WHITE: Close enough.

COMMISSIONER BYRON: The Center for Energy Efficiency and Renewable Technologies.

MR. WHITE: Thank you.

MR. VIDAVER: I stand embarrassed. There is one person who actually volunteered for this panel. If you have ever tried to herd one of these together, you will know how rare that is, and that is Rob Anderson from San Diego Gas & Electric. San Diego Gas and Electric is perhaps closer than the other investor-owned utilities to finding itself not afoul of OTC requirements. I am sure Mr. Anderson could more adequately explain what that means. So, in an effort to reward his enthusiasm for being here today, and to demonstrate to the State Water Board and any other entity or individual who believes that we cannot pull this off successfully, I will let Rob sort of go first and, more or less, address the question, "What do I think of all of this," after which the dais is more than welcome to ask him questions. Rob, thank you.

MR. ANDERSON: Thank you. I am Rob Anderson, Director of Resource Planning at SDG&E. And what Dave did not say was, in that same e-mail note that I volunteered, I also, then, a few lines down, said, "I just volunteered. I better schedule a doctor's appointment."

Just a little bit from San Diego's perspective because I think we are in a little bit different situation than Edison -- I know definitely than Edison, maybe more so than PG&E, and that is really on taking care of our once-through cooling issue, or being able to eliminate those projects, I think we can probably get there maybe quicker than the other plants can. I would not want to say, though, that it is a quick process. I think it is really resulting from the work on the Sunrise Power Link, and knowledge years ago that the owners of the South Bay Power Plant wanted that plant shut down at a date specific, which we are trying real hard to meet. And so I want to say, yeah, we might be close to eliminating it, but it is not because we are starting now, it is probably because we started six, seven, or eight years ago on this problem now. So can the problem be solved? Yes. Just because we may get it done in the next three or four years, I do not think that means that everyone can get it done for three years, this is probably a 10-year process for everyone to go through.

How are we really going to do it? I think what will finish the job, because I think we are part of the way through it, is through the RFO process. There were some things said this morning and I think I would very much agree with, is we try to stretch the RFO's to be as flexible as possible. We do not structure the RFO's saying we are looking for X Megawatts to replace X Megawatts. What we really do when we structure our RFO's is we are looking for moving from a portfolio of plants that included once-through cooling plants, to a portfolio of plants that does not include once-through cooling plants. And by looking at it from a portfolio basis, I think we are not targeting, "Okay, this plant provided this service, therefore we need to go get that same service," but, rather, as we add different plants into the portfolio, services may move around from plant to plant. So we think it is important to look at it from a portfolio basis. Also, by being fairly flexible, we are not -- we have to be a bit restrictive on location because it has got to be within the San Diego zone, the local area, but other than that, we are willing to look at offers anywhere in the zone. There may be offers where the power plant is cheaper, it might need some transmission upgrades, but that might be cheaper than a more expensive plant that does not include any transmission upgrades. So we want to make sure that we look at those things and trade them off as we evaluate the portfolio.

We currently do have an RFO out on the street, the bids are due back to us on August 10th. We are hoping, if we get enough competitive bids, that through that RFO and the evaluation of it, we will be able to select enough new plants that would be able to replace the last of the once-through cooling plants in our service territory, so that is our goal. Whether or not we will meet it or not, I do not know, we are going to have to wait and see, see what all comes in on the bid. As part of that bid, we are asking for new plants, obviously. We are also offering a 20-year contract, so we are not limiting it to 10-year contracts, and I think you heard before that there was a desire from a lot of the new builders to have a longer-term contract.

Around the AB 1576 issue, we really do not see that as being an issue. We think we are going to do it through competitive solicitations. We will then take those contracts to the Commission for approval. We never viewed that law as creating the need to do any special procurement, do it in a special way, so that, to me, has become a bigger issue and talked about a lot more than what it was ever meant to be.

And so finally, and kind of in conclusion, we think we can get there, we are moving ahead. As I read through the staff proposal, the one thing that lingers in the back of my mind a little bit is will this proposal, with all this analysis, slow us down? We hope it does not. We want to work with you to make sure that is not the case. I do not think you want that to be the case, but we really do not want to have lots of new studies to go on, or lots of new work to go on, we would like to get on with the job at hand. Also, we think what will be important out of this, and one of the things we would like to do, is we would like to be able to give some surety or some, as close as we can, dates certainty to the existing plant owners. We used to run both of those power plants, I know what it is like, a lot of them are dealing with capital investment issues. Those issues may not make sense if their plant is going to be around two years, it may make sense if their plant is going to be around four or five years. So we are hoping, out of this RFO, we can then get a plan laid out so the owners of the existing plants will pretty much know what life do I have left. I think that will give them a bit more surety, it will allow them to make better business decisions, and help keep the costs down, down for all of us. And that is all I have. Thank you.

MR. MANSOUR: Yeah, just a clarifying question, Commissioner. I understand from what you said that you have less of a concern than [inaudible] [9:53], yes? Is that correct?

MR. ANDERSON: Yes.

MR. MANSOUR: So I just want to make sure that what you mean by that, so do you mean that the 30 or 40 percent of the generation, if, let us say, with much less than we have now, like the San Diego lights will be on, and the rest is off? Or -- you are not part of that system as a whole, so when Edison has a big issue, it does not affect you and L.A.?

COMMISSIONER BYRON: That is not a clarifying question, that is a trick question.

MR. MANSOUR: I just want to know what he said, "we don't have as much of an issue," I just want to --

MR. ANDERSON: Sure.

MR. MANSOUR: -- what is it that you say you do not have, and what is it that you still have, or just a clarification?

MR. ANDERSON: I think maybe the issue of getting replacement capacity that I think will provide the services the ISO needs, quick starting capacity, ramping capacity, we have been adding that, we will add some more of it. Once we do that, the numbers will add up for a local reliability area that we would be able to allow the once-through cooling plants to shut down, and still meet your local reliability. Okay? I understand that there are wider statewide issues assigned to this, but I am counting on the two gentlemen to my right to handle that in each of their own service areas.

MR. MANSOUR: Okay, thank you.

MR. VAWTER: Rob, if I may, would you be willing to elaborate a little on what you have to get out of this RFO and your understanding of what that will allow with respect to Encino, whether another RFO might be necessary?

MR. ANDERSON: Well, when you issue an RFO, you never know exactly what you are going to get bid-wise. You never know if the bids that come in, when you sit down and negotiate them, you can get to a final agreement and that part is going to move forward. So our goal would be to get enough new capacity signed up under this RFO that would allow, from a long-term look at the local reliability criteria, that we would have added enough new capacity to allow all the existing once-through cooling units to shut down. That is our goal. Whether or not we will be able to get there, I do not know.

MR. VAWTER: What do you think would prevent you from getting there?

MR. ANDERSON: Like I said, it is more of will we get bids, will we be able to reach a mutual agreement with the developers in order to get that.

MR. VAWTER: Okay, thank you.

MR. VIDAVER: Several of the panelists before lunch noted that -- Mr. Pizarro, as well -- noted that we have established a very ambitious schedule, hoping to get information out of the procurement process and directions issued to the utilities as early as 2011 and 2013, to replace once-through cooling capacity. This is not a very long time -- two to four years is nothing and, if we are to reach those goals with respect to renewable energy, we may be foreclosing the opportunity to develop additional infrastructure, or at least making it more costly to meet most local capacity needs, system capacity needs, and meet the state's ambitious renewable energy goals by requiring new capacity to replace OTC plants, to be on line in as early as 2014, and 2015 in some cases, and no later than 2020, and according to that schedule, currently established. I was wondering -- here comes a bushwhack, Mr. White -- how you might feel about the sort of tension between replacing OTC capacity and meeting the State Water Board's policy objectives in a timely fashion, and perhaps either precluding, or making more expensive overall system costs in an effort to reach 33 percent renewables?

MR. WHITE: Well, thank you for the question. First of all, I think that the regulations of the Water Board have already been relaxed, if I am not mistaken, from what was proposed. So the idea of this being in an urgent crisis is something I am not sure is the case. But, I think, first of all, I commend the Commission for putting this subject on the series of topics that it has been looking at on metro gas and renewables, because I think the first challenge is to recognize the need for something we might call "Integrated Resource Long-Term Procurement Plan," in that we have to accommodate a variety of interests and issues to move forward. And I think one of the things we have to look at that has been referenced, but is the attributes of the fossil system we have versus what we need it to be. And I think one of the reasons these plants, the once-through cooling plants, are important is because, in many instances, they are the ones that actually operate the most flexibly on the system. One friend of mine described them as the "old '57 Chevys," you know, they burn gas and they are inefficient, and they have some higher emissions, but they run beautifully for purposes of what we now need. So I think that is an important attribute to keep in mind and it is why the subject is relevant for renewables. But, secondly, I think we need to take a look at the existing fossil capacity and look at how flexible it is, or might be, compared to what we need because we built a lot of combined cycles, a lot of them have been permitted by this agency and the air quality agencies with a very heavy focus on the lowest possible emissions per million Btu's or Megawatt-hour, but this has then resulted in the plants, as I understand it, not being able to flexibly ramp up and down. So all of this new capacity we have added has not helped us in the way that we need help going forward. So it seems to me that one of the things -- and then we have got the priority reserve issue in the South Coast, which is a topic that could easily be alongside this, and perhaps deserving of a future conversation because, there, you have the problem of some of the new capacity that we might like to have for its attributes, if not always this location, is constrained by the conversation about the availability of offsets. And when you talk to the folks in the community groups who are opposing new power plants in their neighborhood, that conversation has gotten more evolved as time has gone by, and the negotiations and lobbying around various Bills to exempt the permits from having to get offsets have crystallized the problem a little bit. And one of the things you hear from them is, "We might be able to agree that there needs to be more capacity, but we've also got to look at what we are going to retire, and what the net emissions would be," which is not the way our planning and siting process is set up. We got rid of the need assessment in our over-confidence of the value of the markets, so we do not now have an independent Energy Commission forecasted need. I am not sure having the Energy Commission alone through a forecast is the answer, given the interactivity and the need for the ISO, the public utilities, the PUC, to all be involved.

Two other issues that bear on this, not to complicate things further, but we have already seen progress and movement towards joint operational planning by the ISO, the publicly-owned utilities, and the IOUs. That process is something that I think came out of the RETI discussions where we needed to look at the value of joint operations. I think we need to add something --

COMMISSIONER BYRON: Mr. White, RETI is another one of those acronyms --

MR. WHITE: Renewable Energy Transmission Issue, pardon me, Mr. Chairman. So there is the other issue we might want to look at in that same light, is what are the possibilities for combining and jointly operating the balancing areas because, ultimately, in Southern California you have two completely separate systems that do not talk to each other for reasons of history, and religion in some respects, and yet, in the basin, were those systems jointly operated, or had access to each other, and for these purposes, you could end up having a significantly less amount of fossil capacity than you would have if you otherwise kept the systems separate. So two specific suggestions I have, one is to examine the capacity of the fossil system to be run differently, in other words, from a renewable standpoint, I do not think we want to necessarily have 20 percent of 120 percent be our goal. At some point, we ought to be able not to keep all the fossil we have and back some of it off, but to back some of it off probably depends on its operating characteristics. The second thing is to really push forward with this joint planning effort that the ISO and the utilities have undertaken, and see what we can do with the balancing areas, with the goal of minimizing fossil emissions while maintaining system reliability. Thank you.

MR. MANSOUR: This is the best speech I have heard since I came to California.

COMMISSIONER BYRON: Well, I will not take offense from that, how about you? Very good, Mr. White.

VICE CHAIR BOYD: One comment, John. You mentioned that, as I have sat here, I have been quite concerned about the number of simple cycle peaker -- large peaker plants -- that we have been asked to put in place, and their virtue is, you know, quick start, quick ramp-up, etc., and you mention in your comments that basically we have not seen plants with those virtues very much in the past. I think there is somewhat of a balance. There is a lot more of them in the cue now, but that is bothersome to me because they are inefficient, they use a lot of gas, I worry about natural gas consumption a lot. And the other thing I do not hear enough talk about, although we heard this morning, as many of us know, that there are lots of new technologies out there that can go both ways, so to speak, they can be combined cycle, quick start, etc. etc., so maybe some of these will sit on the shelf long enough to change the technology to apply. The other concern I have is, I do not feel I hear enough discussion of all the other alternatives to building any generation in a lot of these areas, and I am just taking advantage of your comments, to make that comment. I said it in my introduction and I will say it again, regularly, that there are a lot of other alternative approaches to meet your need, and we need to more cooperatively talk about them in the comments.

MR. VAWTER: May I? If I could say, I think the two things we did talk about just a moment ago is the strategic role of energy efficiency at minimizing that need, as well as the role of demand response, as well as distributed generation. We have a lot of tools in the tool box, the question is how we put them together. And one of the things about the siting process -- and this is a criticism of both the area agencies and the siting process here, we tend to look at these plants in isolation and how their environmental performance is, individually, as opposed to how they operate within the system. It is also a legacy of Order A88 where all the generation was the same and when we could not get preferences, and everybody had equal rights to the grid. I think we are heading towards a policy by default is that clean goes first, and second, that we do seek to move the fossil units from the center of the portfolio to the side, with a very important role in balancing, but not absorbing as much of the energy load as they now do, and I think that is partly because we need to think about using them differently than we have in the past, and I think that requires a different kind of planning and siting process than the one that we now have, that actually is informed by the IEPR, it is informed by the ISO's interest, and it is informed by issues like this, so that when we look at new generation, we have a better idea of what it is for and what it is going to displace.

MR. VIDAVER: Thank you, that would be a general representative of the Center for Efficiency and Renewable Technologies. One of the major concerns that has been expressed is that, with the location of requirements associated with replacing once-through cooling capacity, that bidders into competitive assessment and competitive RFOs may have a substantial amount of market power. This is especially an issue in the ISO portion of the L.A. Basin where the SCAQMD PM10 credits are kind of constraining and a very expensive factor. I would ask that the representatives of the utilities begin by discussing what they believe might constrain or, alternatively, increase participation in RFOs to be held in response to the 2010 and, in Edison's case, 2012 Long-Term Procurement Plan, and whether -- what additional direction that might not be forthcoming, or that is absolutely necessary, that they receive in order to accurately put forth RFOs and provide information to prospective bidders, needs to be forthcoming from the CPUC, and whether they feel that, if the economics allow for it, that simple refitting of existing plants, if this proves to be far and away the cheapest bridge toward a low carbon, no once-through cooling future, if the economics allow it, if they feel that the current procurement process, or a modified procurement process, might allow for that -- I am trying to ingratiate myself to Commissioner Bohn here, paying a lot of attention to cost -- is in place, are not furloughed three days a week, or a month. So, Mr. Cini, I am just picking randomly, if you might elaborate on some of the concerns you might have about schedule and costs, and who is going to pay for all this, and how it is going to get done?

MR. CINI: My field is wide open with that question. Thank you. Let me start with what we would need to do any competitive procurement. We would kind of have to know what plants are slated for retirement, and we never know for sure whether a plant is going to retire because we do not own them, but we would look at sore of the compliance date, and we would look at those plants coming up on their compliance dates as potential candidates for retirement. We would need to have enough lead time and, by that, I think it is five to seven years, given the process we have to go through with the regulatory approvals, permitting, and this is all assuming we can get the priority reserve problem solved because, in a long-term basis, as Pedro Pizarro said, because without the offsets, and there are just no offsets down in the South Coast District right now, we just cannot do anything, we are stranded. But given there is a solution to that problem, a big wishful "if" there, and we kind of know what plants are slated for compliance, by what date, you know, given a five to seven year lead time, we can try to go out and replace that. It would also be good to know if there is any transmission alternatives that are competitive, that should be considered, as well. And actually, those might even be considered outside an RFO process on a separate track, but assuming there is no transmission solution forthcoming, and it is going to be a procurement solution, and it is going to be Edison doing the procurement solution -- I could go into a lot of side bars here -- but assuming all that, we would need to know, obviously, what needs to be replaced. We would also need to know how this is going to fit in with the other initiatives, most notably the potential to go to 33 percent RPS by 2020 or 2025, and how all that is going to fit in because there is probably going to be some increased ramping requirements that we are going to have to fulfill. So we are going to have to know kind of what those are, hopefully the solution set here is not just, you know, build a replacement plant in this particularly place, hopefully there is some latitude, there is some wider geographical area, you know, the wider the geographical area is, the more opportunity there is for competition. And if you have got to build a plant here, you have got all kinds of market power issues, if you have got to build a plant within a 15-mile radius, there are all kinds of market power issues, if it is a broader area, there is more competition, and we like to see competition, frankly, that is the way you are going to get the best result. So those are the precursors we would need to do this. And I have to say, you know, this is a huge undertaking because, in our service territory, excluding the nuclear now, there is about 8,000 Megawatts of generation that is 40-50 years old, that uses once-through cooling, and to put a price tag on replacing that, a simple rule would be $1,000 per Kilowatt, that is $8 billion, and then you add on the transmission to interconnect it, and we heard from Dennis Peters, the high figure was $4 or $5 billion, so maybe a couple billion dollars, I do not know, but I think you are easily talking $10 billion, and you want to spend that over the next approximately 10 years, that is a lot of money, and when you add on that the cost to go to 33 percent RPS, it is a lot more money, when you add on the combined heat and power goals the state has, 4,000 Megawatts incremental there, that is more energy efficiency, and the list goes on and on. You have to build the transmission to interconnect the renewables, it is another huge cost. I am just kind of worried about the combined total of all these initiatives, and who is going to pay for that, what the total price tag is going to be. Is it just going to be just too huge to swallow? I mean, basically what we are talking about here with all these combined initiatives is to rebuild the grid in about 10 years, and, I mean, from a cost perspective, that is a big issue, from a portfolio perspective, that is a big issue, too, because you want to just suddenly do everything in 10 years, assuming you can even do it, assuming you can do it with the utilities financing it, and the utilities' balance sheets can bear it, which I am not sure that is even possible, that is something that needs to be examined. But the wisdom of doing a whole portfolio in the next decade of generation for the next 40-50 years, you have to question the wisdom of that. Technological advances occur over time and, if you do everything at once, then you lose the benefit of future technology, so I just have to wonder, I mean, these are some of the things that are running through my mind and through the minds of people that work for Edison, and it is just a big big deal, and I am glad that I am here to speak to some of these issues today, and I really could go on and on, but maybe I should just stop at this point.

MR. VAWTER: I am sorry for the open-ended question. I will try to return to you with something -- a couple of things more specific. Mr. Monardi, do you have anything --

COMMISSIONER BOHN: May I -- just a question if I could. I am struck with two concerns from your comments. First is it is an impossible problem, therefore it cannot be solved. That is probably not a good answer. The second piece of it is, all the things that you outlined, quite rationally and quite sensibly, in terms of information you need in order to make the most sensible decisions, where do you look for that information to come from?

MR. CINI: Okay, well, first I did not mean to say it is impossible, I hope I did not convey that --

COMMISSIONER BYRON: Well, you conveyed some other things, too. You also said energy efficiency and renewables and combined heat and power were all going to cost more and, of course, the policy of the state is that all economically achievable energy efficiency -- we are not after the energies that cost more, and combined heat and power should essentially be cost savings because of the increased efficiency. And you also indicated that these were the statements of other Southern California Edison employees. So I am not as kind as Commission Bohn on this, I think some of your statements were actually quite incorrect, and he said it much more kindly than I, but I was troubled by your comments, as well.

MR. CINI: Well, I am sorry. I did not mean to trouble you, but I am talking about capital investment, and capital investment costs a lot of money. We have seen this in our procurement today, there is a huge disconnect between -- as one of the other panelist said, I believe Alan Comnes -- what it costs to keep an existing plant around, this is what it costs to put a new seal in the ground, including all the transmission interconnected, and that is true whether you are talking about a renewable power plant, combining heat and power, or a new fossil plant. They all cost a lot of capital, about a thousand for a typical number for a combined cycle might be about a thousand dollars per Kilowatt. So I think there is a big disconnect between just keeping what you have around today, keeping it running, versus putting a lot of capital investment in the system, and that is what I was talking about, the increased capital investment that has to be made. So I hope that clarifies it. Now, I do not think it is impossible. Maybe I am more addressing the time scale in what is all done, and the more you spread out the time scale, and the more feasible it is, I honestly do not think you can do everything by 2020, all these once-through cooling replacements, all the 33 percent RPS, I do not think that is even achievable. I mean, we could try our best, but honestly, I just do not think it could happen that fast. But on a longer time scale, I think it is possible. I think these replacements could happen anyway, over time, because these plants are 40 or 50 years old, they need to be replaced at some point. But in the next 10 years? I am just saying it is a daunting task.

MR. VIDAVER: The task is perhaps slightly less daunting for PG&E with a transmission solution for Potrero already in place, and part of Contra Costa, I believe, no longer needed because of the arrival of the Gateway project, but there remains Pittsburgh and the remaining units of Contra Costa. So, Mr. Monardi, if you could address what information that PG&E might need to move forward, and how an RFO might best be structured?

MR. MONARDI: Thank you, David. And I also would like to point out that PG&E has taken proactive action in terms of replacing Humboldt Bay Power Plant with our repower, which should be on line some time in 2011. A couple points I want to make. First of all, I want to address just kind of a foundation, you know, PG&E does follow the loading order, PG&E in its cost-effective, energy efficiency and demand response and renewables obviously are preferred resources. PG&E also obviously is working through the long-term planning proceedings, which determines its need for the residual resources, if you want to call them that, and included in that is an assumption about retirement of once-through cooling units. So that all gets baked into our specific need which drives our RFO, and I want to make sure everybody understands that this process is a process that is, you know, obviously worked through the CPUC process, and it is a number of stakeholders that participate in it. I am not sure there is a need for another additional process on top of that. Through that process, obviously, we come up with a need for resources which are identified, typically those are resources identified as being operational flexible. Obviously, that operational flexibility is important for a variety of reasons, it meets the portfolio needs that a number of parties today have mentioned, the need to integrate renewable resources, as well as the need to replace the operational flexibility from existing once-through cooling units. And PG&E has actually gone through a long-term RFO process in 2004, and we have identified a number of units that have come through that, including the replacement for Humboldt, as I mentioned, and it is the tail end of a RFO currently right now. A couple things that we have taken away from that process. Number one is, we think that it is better to be more general than specific in these RFO's. I think you have heard a number of parties say, and I think say correctly, that you want to have a competitive process, and our opinion is that, what we have discovered is, having an open and as competitive process as possible will tend to drive down costs and benefit the consumers in the long-term, and so we think that is an important attribute. Getting too specific probably constrains the options that counterparties have, and it also, and our feeling is, it reduces innovation. And one thing that we are always surprised at, what we have discovered is, people come up with all different types of, you know, new technologies are coming up, you have heard some of them being touted today, these technologies are highly flexible, they are efficient, and we welcome that in our RFO, so we do not want to get too overly specific. Likewise, in terms of finding good locations to site power plants, that is something that we find that, you know, the market is usually fairly good at determining -- developers are fairly good at scouring sites and figuring out where the best place is to site new power plants. Then, at the end of the day, getting all these offers, PG&E evaluates them on a number of different factors, including economics, obviously, is an important factor. But also, when we have an RFO, I also want to point out, it includes brown field sites, it includes repowering, and it includes green field sites. We do not include in our RFO, and this is to speak to David's earlier point, this concept of refitting existing power plants. From our perspective, that is not really fulfilling the long-term planning proceedings' findings of basically new steel in the ground. At the end of the day, new steel in the ground is an important attribute; we are doing that for an important reliability need. So if we threw in refitting there, the concern that we have, and I think it was also voiced earlier today, is that you are going to basically -- you will have investors who are looking to invest new steel, new power plants, or they are not going to want to compete against something that is an existing power plant that only has an incremental upgrade. We are not also convinced that refitting these existing once-through cooling units is really a cost-effective solution, in any event. So, as I was describing, our RFO process has generally been very flexible, and we have opened it up to a wide variety of technologies, and we typically define the number of Megawatts we need, we typically define operational flexibility that we are looking for because, obviously, that is what we are trying to achieve, and then, at the end of the day, we evaluate it against a number of different attributes, and those attributes include the environmental impacts, it includes the consideration of repowering as an important attribute, it includes viability, and viability is a critical component when we look at new steel. And obviously someone who is repowering a power plant is going to have a highly viable project, and that is something that is an important attribute in our consideration. So those are just several of the factors that we consider.

That being said, we have actually gone out and have done a targeted RFO. We needed to do that for Humboldt. That was a very unique load pocket sort of situation. But one of the things that we did when we did that, and I think this is something that I would like to point out, is we actually did look at the cost of replacing that power plant with transmission, and we actually had that as an alternative. When I say "transmission," you just cannot say "transmission" alone, we had to obviously get the Megawatts from someplace else. So the question was, do you build the transmission line and buy the Megawatts from someplace else? Or do you try to replace and repower the plant at that specific location? We did look at that cost trade-off, and I think if we are interested in moving forward and in phasing out OTC in a cost-effective manner, and we want to have a flexible RFO process, we need to have information on transmission alternatives. We need to have -- the utilities need to have that information, as well as just the general marketplace needs to have that information. What does it cost to build the transmission upgrades -- I should say -- and we do not have to go crazy and talk about every potential transmission upgrade, but we really should identify the more cost-effective transmission upgrades that could be used in addition to a new site, outside of the load pockets, or outside of the LCR, that in tandem would be a cost-effective alternative to somebody building within that load pocket. And that would actually, I think, improve the competitiveness of those RFO options out there. And it would give the utility, I think, a better position to drive the least cost solution in terms of procuring these types of Megawatts.

The last thing I want to point out and I want to say is, I think there has been a lot of bashing or -- and I am using the term, you know, it is a fairly strong term, but I think there has been a lot of negative statements about combined cycles that have been made about, you know, different technologies, new technologies, and I just want to be careful about that because I think the older or previous vintages of combined cycles, they were built for base load, previous vintages of CT's did not necessarily all have these quick start capabilities. If you look at the most -- and this once again gets back to my theme of keeping these RFO's flexible and opening it up to different technologies, is if you look at the new technology, it has a tremendous amount of operational flexibility, and they are very clean. And I do not think that you can say that this new technology is, as a portfolio, when you add it onto the portfolio, and I think that is another important element, when you look at them as a whole, it is no less, I would say, operationally flexible than what we have right now in once-through cooling units. I think the important thing to remember is that they are different. Once-through cooling units have a different operational characteristic than a fleet of combined cycles, or combustion turbines. They are operated differently and, as a system operator, I think you have to think of them differently; but, at the end of the day, we see a lot of flexibility in these new technologies. So anyway, I have said a lot here in a few minutes and I have spoken very fast, so I will just stop right there.

COMMISSIONER BYRON: Mr. Mansour?

MR. MANSOUR: Yeah, I have again another clarifying question, a really different question. You said that the utilities need information about the transmission and all this so you can go forward. What agencies want, or what utilities want, first of all, we did the cost [inaudible] [43:37] actually from the utility, so when we want to know what the cost of transmission is, you ask the utility, we do not do it ourselves, and no one else other than the utility knows the cost of [inaudible] [43:42]. Secondly, the utility knows even how much capacity is required locally because that is where they [inaudible]. So I just had one -- what is it that you are missing, from who, to make that comparison?

MR. MONARDI: Well, I think that, at the end of the day, you bring up a good point. Obviously, the PTO, the utility, and I am still working under the vestiges of 2004, so I have not talked to our transmission planners too much --

MR. MANSOUR: Oh, I see.

MR. MONARDI: But now I can actually talk to them, but they generally do not like to -- they generally do not like to talk to me.

MR. MANSOUR: Right, it is not confidential anymore.

MR. MONARDI: But I think the important thing is, though, it is really the CAISO, though, that determines the local area reliability requirements, right? And so I think the CAISO has a very important role in determining what are the transmission -- well, the utility can determine what are the costs of building various transmission upgrades, but I think it is the CAISO that really needs to identify what the transmission fix is.

MR. MANSOUR: Yeah, but what I am saying is, the ISO does not just sit in a room by itself and determine -- we get information from the utility, load for gas and the capability of the transmission system, and from the transmission side of the company, and then we accomplish, say, "Here is what is missing," and how much generation we want. So all of that, I want to put my hands on what is it that is missing, and I know that you are talking about your one side of the additional dollar, but let's talk about just the utility holistically. I want to make sure what is missing, that I can put my hand on, and say we will need to fill that from what you were talking about.

MR. MONARDI: I think what needs to happen from our perspective, I am talking from the energy procurement perspective --

MR. MANSOUR: From one side of it.

MR. MONARDI: And what I think needs to happen is, really, we need to be able to say that -- and I am not going to point fingers, transmission or the CAISO -- what we really need to say is what is the cost of the transmission alternative, that with additional generation, somewhere else in the system, can relieve the local reliability requirements. And I think that is actually a joint task between the CAISO and the utilities, that needs the help to develop that.

COMMISSIONER BYRON: I would just remind you, and I did not want to interrupt you, Mr. Monardi, but speak right into the microphone, gentlemen, because we have got lots of folks listening at home, and for those of you listening at home, CAISO is another acronym that has been turned into a word, and that stands for Mr. Mansour's Independent System Operator -- actually, it is the California Independent System Operator.

MR. VIDAVER: We have on line Hamid Nejad from the LAPWP. Can you hear me?

MR. NEJAD: Yes, I can. Good afternoon.

MR. VIDAVER: Good afternoon. And we can all hear you. You are a rather unique animal, as it were, and an integrated utility. Some of the people sitting here on this panel are probably a big jealous, you get to decide what to build, your ratepayers are a little more captive than anybody else's in the long-term, you even do your own CEQA analysis, you do not have to worry about the CPUC, or the Energy Commission. So I imagine there are people who are thinking this is all going to be a piece of cake for you. On the other hand, you are sort of pinned against the coast in Los Angeles and have three once-through cooling plants that play an indispensable role in providing reliability not only for your utility, but for your balancing authority. I was wondering if you could briefly speak to the plans that you have for complying with the Water Board policy, what you see to be the investments that you are going to undertake, that you have planned to undertake, if only for business reasons, that would reduce water flow, and what additional steps you see would need to be taken to comply with policy, and whether or not those are technologically possible and, if so, what the cost implications of those might be. I realize that is a lot to discuss, and I think you probably have about five minutes. Is that something you can do? I will start the clock when I finish talking.

MR. NEJAD: Thank you very much. So those are a lot of questions combined into one, I will try my best to answer as best I can. The LAWP has been working on upgrading some of its fleet. We have [inaudible] [49:09] and there is also some of these repowerings we have, reduced ocean cooling, we have reduced the number of our ocean cooling plants from 18 to nine, and we do have plans to do additional repowering that will replace some of these old units, more efficient either combined cycle, or combustion turbine units. We are moving towards more and more renewable generation, but we find that, because our system was built around these coastal plants, we have too many limitations in reducing the capacity in any of these existing plants. In fact, we think that having the capacity, having at least the same capacity that we have, you know, existing plants, is [inaudible] [50:18] to have more renewable energy available to our customers, and then having the back-up of these units in case it is needed. We find it very difficult to meet the load on the peak hours with existing renewable technology and availability of energy in the markets. So, let's see, what our current plants call for another repowering at Haynes Unit, we are getting two old units, units 5 and 6, and we are planning to repower those with six -- combustion turbines, about 600 Megawatts, and we also have plans on our Scattergood generating station to get two very old units with combined cycle, it would be a one and one combined cycle, and gas turbine. I believe you asked if it is going to be difficult for us to meet these goals and the answer is, absolutely, yes. We have very limited space, we have a lot of concerns of the neighbors about noise, cooling tower drift, size obstructions, noise, and it seems pretty difficult to meet those challenges technologically, let alone the impact on finances because we are spending a lot of money also on renewable generation, and having to do all of these in parallel is having huge financial impacts on the system. Is there any more specific parts that I can answer?

MR. VIDAVER: Have you done any studies of the transmission upgrades that would be necessary to further lower the in-basin capacity needs at Haynes, Scattergood, and Harbor?

MR. NEJAD: I believe we have done some transmission studies, and we are currently working on some transmission upgrades, however, the majority of the generation of power that is coming to our system, is coming from up north. And it would be very difficult to have generation that is coming from there on some of the southern portion of the system. Is it possible? There is a possibility for our neighboring utilities are making a lot of generation, or have another program on that side, but we are physically relying on our own system to provide that power, and if we are relying on our own power, it is going to be very difficult to meet that, and also it has become a huge reliability issue if there is any problem on the northern side, to be losing all the power; we are going to have major reliability issues, of course, and for neighboring systems, too.

MR. VIDAVER: Thank you. I do not know how long you have been on the line, there was a proposal -- a suggestion about how you could alleviate the problem of a lack of interconnection with your neighbor, and I am not sure whether or not you would appreciate it. Thank you very much.

COMMISSIONER BYRON: Mr. Vidaver, because the clock is at your back, I will point out to you that we are at 2:15 and you have two panelists we would like to hear from.

MR. VIDAVER: Okay. Do you have any questions of Mr. Nejad?

COMMISSION BYRON: Please.

MR. VIDAVER: Last, but certainly not least, I would like Mr. Tisdale and Mr. Florio to comment on what they have heard here today and any concerns that they have on behalf of ratepayers regarding this process, how procurement might need to be changed to result in least cost outcomes --

MR. TISDALE: Should we go at the same time? I will be brief. My name is Matthew Tisdale, representative of the Division of Ratepayer Advocates. Our mission, of course, is to obtain the lowest possible rates consistent with safe and reliable service. Consistent with that mission, obviously, this is a question which is near and dear to our hearts, I appreciated hearing from Commissioner Bohn this morning that there is a noticeable lack of discussion of the costs of this process, and would be interested in working with you and other parties to engage in your suggestion on some sort of an net incremental cost estimate of the transition. That said, we want to talk a little bit more about the way we use competitive procurement to do this at the lowest possible cost. We do have some expertise in the subject, we do monitor all of the utility RFO's as a participant in their procurement review groups, so that experience is what informs our remarks.

The main message I would leave is that all options should be on the table, should not be restricting the procurement solutions that we are discussing; I believe that is pretty consistent with what I have heard today. All options, starting with competitive procurement through RFO's, but including transmission solutions, cost based bilateral agreements, and/or utility-owned generation. As a member of the PRG, we do watch these RFO's and I would say with confidence that we believe cost competitive RFO's can go a long way in mitigating our problem, and we would only offer the caveat that, in structuring those, we should be as broad as possible, both in terms of location and in terms of the product technology, that we are trying to get broadly defined RFO's, is the emphasis there. In addition to defining the RFO's broadly, we would suggest that we create further competition in the market by sending a clear signal that we do have an appetite for alternative solutions, for transmission solutions, for UOG, or for cost based bilateral agreements. And I would echo Mr. Monardi's comments in saying that, the sooner and more aggressively we can identify alternative solutions, and to the extent possible price those solutions, that will give us a, we feel, more competitive advantage in the RFO's that we would use to mitigate this problem. So, given that we are short on time, I will stop there and be happy to answer any questions. Also, of course, looking forward to hearing from Dr. Florio.

MR. FLORIO: I have been promoted. Mike Florio, Senior Attorney for TURN, The Utility Reform Network.

COMMISSIONER BYRON: Mr. Florio, I am going to ask you to take the microphone and pull it right in front of you.

MR. FLORIO: Thank you.

COMMISSIONER BYRON: Thank you.

MR. FLORIO: Yes. I have not heard a whole lot that I disagree with here. I think that obviously our concerns center around cost, and related to cost, the issue of potential market power. And I do think that, like DRA, we have monitored the utility RFO's very closely and feel that the process is robust enough to encompass these new needs. I mean, this is not something we just discovered, people have known that this issue was coming, and the utilities have already done a lot of procurement in local areas that can help to reduce OTC generation. I think, clearly, the Los Angeles area is the most difficult because there is so much OTC generation, and just by virtue of the size and complexity of the urban area there, so many issues including the priority reserve that all have to work together, but I think your staffs have done an excellent job in moving us to the point we are at now, and I was very pleased to read the report and see that a lot of good work had been done. I think, in terms of the ability of RFO's to achieve the goals, I think a lot depends on, as others have already mentioned, how specific locationally the needs are identified to be. Both the Bay Area and the L.A. Basin local capacity areas are quite large, but if you read the details of the ISO's local capacity requirement studies, not every unit in every location is equally effective at meeting the local reliability need. And, in some cases, you know, a plant at the southern end of the L.A. basin may be fulfilling a need that simply cannot be met by a plant located on the eastern edge. And I think, you know, hopefully we do not get into a situation that someone said, where we need a plant within a 15-mile radius. It is going to be very difficult to get effective competition if the need is defined that narrowly. But I think that there is talk of a 10-year LCR study. I think, to the extent that can delve into these effectiveness issues and really isolate the extent to which there are within local area constraints that have to be considered, that will be very helpful. But another question that has come up a lot in our RFO's, in terms of these other characteristics, are things like ramping capability, quick start, you know, there is not a lot of clarity around how much of that do you really need, and I think, if any help that the ISO can give in that area would be very helpful. We know we need ancillary services, we know we need ramping, but is it 300 Megawatts, or 1,300 Megawatts? It is not always clear. And to the extent that the folks who are evaluating an RFO can be as well informed as possible about what is needed from an electrical standpoint, I think all the better. And to the extent that the market is informed through the RFO, the more creative solutions we are going to see. I want to second the comments that we have seen a lot of evolution in the technologies, even in the last 10 years, and we are seeing offers that include the hybrid types of units that may have a higher heat rate than an older combined cycle, but is much more flexible and can provide the ramping and cycling that maybe a unit built 10 years ago cannot. So there is a lot being done and there are always surprises in RFO's about what someone has come up with, and we want to continue to encourage that. But I do share the concern that we are trying to do an awful lot in a short time, and even if some of the things that we are doing are cost-effective over their 20-year horizon, the upfront costs may be very significant, and obviously that is something we need to keep a close eye on, replacing a fully depreciated unit with a brand new unit has a definite cost impact in the short run, that added to all the other initiatives we are pursuing, our rate situation is bad and getting worse, so I am glad to see that there is continuing concern on that front. Thank you.

COMMISSIONER BYRON: Mr. Bohn?

COMMISSIONER BOHN: I know we are behind schedule. Let me just ask Mr. Florio a quick question. The uncertainties that you refer to, ancillary services and the rest, where would you look for answers to that? Is that something that you expect the CAISO to simply deliver? Or does it come as part of the RFO? Where would you get the information such that it would be satisfactory to clarify it within the competitive process?

MR. FLORIO: Well, what we hear from the utilities often, and we are hearing one side of a conversation, I acknowledge that, is that, while we ask the ISO and they could not tell us, and we do not know now -- I think some of that goes back to when the generation and transmission arms really could not talk to each other at all -- I think it is something that the transmission element of the utility, working with the ISO, can help to develop. But the folks who do procurement, you know, the folks who are sitting here, are not the ones in the utility who have that information, and whether it is through their transmission departments working through the ISO, or through the ISO directly which, I think, to the extent things come through the ISO, they can be public and everybody can see them, and people feel maybe that is a little more fair. That, I think, is beneficial because there are questions that just nobody has the answer to when you are sitting around looking at the bids in an RFO today.

MR. MANSOUR: Just let me -- maybe what is known now and -- in terms of what is required to support RPS, which we think about, frankly, it is after starting a new market in MRTU, this is the number one job for us at ISO, to make sure that the system can accommodate whatever volume is coming from the RPS and [inaudible] [66:42]. For the 20 percent target, the entire capability of a existing fleet is needed. Now, let me clarify that. What I am saying, some of that will need more of, so we need less energy from the existing fleet [inaudible] [67:01]. But for ramping, we know that we need 25 to 30 percent more than what we have today. In the early morning hours today, they spend about 7,000 to 7,500 Megawatts over three hours, you would need to add to that about 1,500 to 2,000 Megawatts of ramping up. Does the existing fleet, which did not do that before, have it? So we are going on paper, it does. In reality, that is what we are checking, unit by unit. And those units, as Mr. White delicately described, have actually capability more than they even think about as [inaudible] [67:39] talk about. Yes, they are better than before, but not as much as what you get from those [inaudible] [67:44]. So the regulation that count for error in forecast and, believe me, we have done a lot of work the last year and a half to see if we can improve the data forecast for when, for example. Regulation would increase by about 500 Megawatts of regulation requirements, again, from the existing fleet, or otherwise. So those -- for the 20 percent we know, reasonable extent, we have done an [inaudible] [68:12] and that study is public, and has been published now for over a year and a half -- for the 33 percent we do not know, and the reason we do not know is the following, it is about half of what is on paper, what is signed, especially when it comes to solar, and solar thermal, where we really do not even know how they [inaudible] those technologies, and that is what we are working on. Like some of the stuff, for example, there is about 8,000 to 9,000 Megawatts of a type of solar technology of which, worldwide today, there is less than 500 Megawatts. Now, we would like -- in 10 years, we would like to be in the forefront of application of how do they behave, and what the characteristics are so we can [inaudible] [68:55] them and we do it as -- now, what we say to account for this [inaudible] flexibility, that is why we are saying, you know, as we go, we know what our collective objective is, to get RPS, AB 32 on all of this, have flexibility on the fleet as to what we phase out and what we phase in, and what we replace it with, make it flexible enough so an entire portfolio of initiatives can be accommodated in a reasonable way, especially that we are talking about 10 years, so the stuff that is known, we have been publishing it for more than a year and a half, you can extrapolate from that, some say, it will be more than this, but at least it will give you certainty for last two or three years, of certainly a way or a guide of what you should at least use as a corner stone over the next 10 years. So I just want to be clear on what we know and what we do not know. Do we have enough to work with, at least to know what not to do or what to be careful about? I think so. In terms of cost and in terms of cost of transmission, this state has come a long way in transmission. You talk about the 890 process, long-term planning, including even talking about the joint planning with the municipals, and whenever we are talking about 10 years of load capacity requirement, we have come a long way. So the unknowns are getting less. But, at the same time, it also calls for flexibility in terms of the full package. I just wanted to make that --

COMMISSIONER BYRON: I think we -- Mr. Vidaver, do you have something else you need to add at this point?

MR. VIDAVER: No, I do not.

COMMISSIONER BYRON: I would like to add one more comment, as well. Just so it is clear to everybody here, how important Mr. Florio's and Mr. Tisdale's responsibilities are in this procurement renew groups, being the non-market participant, Mr. Florio is one of the few that participates and provides input to the procurement process, and it is interesting to hear your comments and some of the information that you need, going forward. So my question for you is, based upon the customer class that you represent, the investor-owned utility, residential customer, do you think there is a willingness to -- and I will go back to Mr. Cini's comments earlier -- do you think there is a willingness to pay more to help provide some of the solutions that are going to be necessary to address once-through cooling in the procurement process? Will you pay more?

MR. FLORIO: Yeah, well, I think we are going to, whether we would like to, or not. I think there is in the public a willingness to pay for clearly identified benefits, and I think the once-through cooling may be an issue that has not gotten as much public attention, perhaps, as air quality, but certainly, you know, there are some folks who are very informed in that area, and have been trying to do the public education to make it clear, you know, when the salmon run does not show up for a couple of years running, people start to notice, and there are other problems of a similar nature. So I think, you know, for example, our organization has been willing to engage in raising the AB 1X rate cap because we realize you cannot achieve all of these other objectives and not have some amount of rate increases. And, at the same time, of course, we are in an economic tailspin where more and more people probably cannot pay their utility bill, they cannot keep their homes, so it is a difficult balance and we appreciate all the attention that the agencies are giving to working together to try to do this as cost-effectively as possible.

COMMISSIONER BYRON: I know we are late, but I also feel we may have shortchanged Mr. White. We will give you the opportunity, John, just for last remarks because we really addressed you earlier on and --

MR. WHITE: I appreciate it. The badgering I took earlier was my opportunity --

COMMISSIONER BYRON: Bushwhacking.

MR. WHITE: I think it worked out usefully. Just one thought. A couple thoughts that relate to this last topic, I think there has been, in this conversation, sort of a recognition that we have a lot of silos in which these decisions are being made, even within the utilities. The fact is, the power flow studies are the utilities database, and I think one of the things we need is to really put the integrated back into resource planning and I think we could start by taking a look at, statewide, the capacity to add renewables with an existing transmission capacity, not just waiting for the new capacity while working on it -- by looking at how we operate the fossil units. I think we have sort of made the assumption that we are going to keep operating the fossil units the same way that we have and are today. And as Mr. Mansour said, there will be an opportunity to displace energy with renewables, but we may also be able to displace some of that fossil capacity more directly if we look at it carefully, and if we examine these assumptions. I think that this requires more of the kind of meetings that you are doing, and I commend the Commission for the work on the IEPR, for getting through some of these topics, but it seems to me we need to work at trying to integrate the planning that the utilities and the agencies are doing more than we have. I think the air quality issue is very very important, but we cannot just do not do fossil onto the existing air pollution problem without some consequences being revisited, and I think there may be a way to actually minimize costs by not just adding these all up, but looking at how they relate together, looking at how the distributed generation, for example, could help with some of the locational market powers that were described, looking at how renewables can minimize fossil consumption, and look at how the transmission can be done synergistically to accomplish all these goals, while minimizing costs, instead of just adding them altogether.

COMMISSIONER BYRON: Thank you. And with that, I am going to thank this panel very much for being here for their input. And if we could transition quickly, Ms. Allen, if you will come forward to the podium and you can start introducing your panelists as they take their seats. And we will transform ourselves into the next panel as quickly as we can, only because we are behind schedule and we have a full calendar. Ms. Allen, you go ahead and start whenever you are ready.

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Agenda Item 6: Panel 3: Changes to Power Plant Licensing

MS. ALLEN: Good afternoon. This is Panel 3, related to power plant siting. I am Eileen Allen. For those of you in the room who have not worked with me before, I am the Manager of the Commission's Siting and Compliance Office. On behalf of the entire Siting staff, I can tell you that, in addition to the role that the staff has in fulfilling the Commission's responsibility for recommendations as the California Environmental Quality Act lead agency, looking at proposed thermal power plants that are 50 Megawatts and larger, the entire Siting staff is keenly interested in these resource and policy issues. So we are very happy to hear from the panelists and others on these questions related to replacing once-through cooling capacity.

In the convention that we are dealing with today, I am going to go slightly out of order on the questions. We will be starting with number two, and then that will be followed by number one, three, four, and five. It is time for me to ask the panelists to introduce themselves, so could we start with Alan on the left?

MR. COMNES: Hi. I am Alan Comnes with NRG Energy, Incorporated.

MR. NAZEMI: Good afternoon. I am Mohsen Nazemi, Deputy Executive Officer with South Coast Air Quality Management District.

COMMISSIONER BYRON: Welcome.

MS. PHINNEY: I am Suzanne Phinney, Energy Program Director for the League of Women Voters of California, and I am following in the footsteps of Jane Turnbull, which we all know is a very tough act to follow.

COMMISSIONER BYRON: Boy, I would not have included that in my introduction. Thank you, Ms. Phinney, for being here.

MR. PETTIT: Good afternoon, I am David Pettit. I am a senior attorney with the Natural Resources Defense Council. I am a lead counsel for NRDC on the Priority Reserve matters that have been mentioned many times today.

COMMISSIONER BYRON: Welcome.

MR. HARRIS: Good afternoon. I am Jeff Harris. I am a partner in the law firm of Ellison, Schneider & Harris. I am here on my own behalf today, not wearing any particular hats for any clients, but we represent gas generators, renewable generators, wind, solar, the whole variety of folks, including some folks with once-through cooling. And just a quick caveat, again, I am here on my own behalf and not for any of my clients.

COMMISSIONER BYRON: Nevertheless, you and I both should be wearing hats.

MR. HARRIS: No one needs a hat more than a bald guy.

MS. ALLEN: We also have the possibility of a panelist phoning in, Jane Williams from California Communities Against Toxics. Is there anyone on the phone right now? All right, we are ready to begin. Mr. Nazemi, could you lead off with responding to number two?

MR. NAZEMI: Sure, I will be happy to do that. Thanks again for inviting me to this workshop. I have been here before and I continue to participate as long as is necessary to resolve the issue related to power plants. I think the question relates to what are the pros and cons of making the offset credits from district available to power plants, compared to the other sources that might be using those credits. And I think it is important for the Commissioners and other members here to recognize that, during the 2000 and 2001 California energy crisis, our agency -- and I am going to, in honor of not using acronyms here -- instead of SCAQMD, can we all just refer to "the District" as our agency? The District did recognize that there was a need to put additional generation on line to avoid black-outs that were happening at that time, and also to avoid the use of the more dirtier, diesel back-up generators, which was a very significant concern to our agency, as a leading agency for controlling air pollution and the worst polluted area in the nation. So we had experienced this before and we did amend our rules to allow power plants to access the District credits due to shortage of credits in the open market. When we, in the mid-2000s were in receipt of additional projections from the state agencies, the Energy Commission and CAISO, in terms of potential additional shortfalls that will be coming in the coming summers and in Southern California, in particular, and not the rest of the state, but Southern California, our Board, once again, took another action to allow the use of the internal credits by power plants, but at the same time, there were also discussions with respect to once-through cooling that was between Water Act requirements, the court decisions coming out, and we know that we have an aged power plant fleet in Southern California, but also the other factors were the implementation of the AB 32 and renewable portfolio standards. So why did we go forward with this, considering there are some pros and cons related to that? When we looked at the credits in the open market to build additional new generation, we found that there are not enough credits available in the open market. In fact, if you look at the three power plants that were able to obtain through the RFO process long-term contracts from Southern California Edison, the NRG, El Segundo, the CPD Sentinel, and the Walnut Creek Mission Energy Project, and you look at the amount of credits that those three power plants alone would have needed, those were twice as the total number of credits that were out in the open market for PM10. And I have to point out that the credits that are in the open market are not necessarily all available for sale because some of those are held by companies that have their own future projects, that they would need to use those credits. The other reason, and maybe in response to whether or not these credits should be available to power plants, and their projects, we looked at our bank accounts and we determined that there were actually adequate amount of credits available for power plants to be used, as well as the other sources, such as essential public services, small businesses, and other projects that use our credits. The only difference was that those other sources will get the credits for free from the district, based on policies that our governing board has established in the past, whereas we determined that the power plants need to pay a mitigation fee, which in turn, we take that money and reinvest it in emission reduction projects with a third of it actually going into solar renewable energy in the areas impacted by the power plants. But it was to be used only as a bank of last resort, so we still required the power plants to look out in the open market and see if they can get those credits first, and if they could not, then come to us. So it was not an issue of, well, there is plenty of credits in the market, why not use those.

The other thing that I want to point out is that, through this process, we did not just say, well, any power plant that wants to use our credits is free to come forward and get it. We put a lot of restrictions and a large number of it had to deal with the community concerns that we heard during our process to provide these credits. We made it necessary for the power plant to have, for example, a long term contract before they can obtain our credits. We made that requirement to have a CEC license, or we said you have to be a municipality that you actually have designed your project to serve your native load. And an example of that is the Vernon Power Plant, which is in front of the Energy Commission, I believe, that we ended up actually denying their permit because they were a municipality, they proposed to build a project larger than their native load demand, and they did not have a long-term contract. So we did not provide credits for that type of a project. We also put additional limitations on new and repowered plants to be able to get credits for us, for example, we said you have to be more efficient, cleaner, and have less toxics emissions than any other project that would otherwise provide their own credits. So, again, put additional restrictions that would make sure that not every power plant that comes through will obtain credits from the district.

When we looked back at our existing fleet, we recognized that over 7,000 Megawatts of power plants in Southern California, in our District, actually, not just Southern California, are once-through cooling. And when we look at the age of our power plants, more than half of our power plants are 40 years or older. And I know, for the young folks around here, 40 years is very old. But also, when we looked at how would the efficiency requirements under AB 32 and renewable portfolio standard meet, as Mr. Mansour indicated, in terms of ramping up needs would be satisfied, we felt that those are all important issues that need to be addressed. However, I think you heard from Mr. White about the issue of replacement that, you know, we do not want to just build, build, build, we want to replace the existing old power plants. And I want to point out that, in the early 2000, during the energy crisis where we allowed our credits to be used, we actually permitted over 4,000 Megawatts of new power plants; but, at the same time, over 3,000 Megawatts of older, dirtier and less efficient power plants, or units, were taken out of service. So, it is the chicken and the egg, but it really needs the reliability to be there before you can remove existing power plants from the fleet.

Now, in this process, as you heard from Mr. Pettit, NRDC filed a lawsuit challenging our rule amendments to allow power plants to access credits, along with a number of other environmental organizations and, as a result of a State Court decision last year, our agency is prohibited from the ability to use offsets for licensing of power plants, so permitting of power plants, as well as other permits for essential public services and other projects. Presently, there is legislation that has been sponsored in proposing California to address this court decision under Senate Bill 696. I should point out that NRDC and other environmental organizations had also filed a federal lawsuit that basically challenged all credits that are in the District's possession, and earlier this month, that lawsuit was dismissed by the Federal Judge. So with the passage of SB 696, we think that will smooth the process for the District to be able to grant credits to power plants and other projects, and basically these are reasons and pros and cons that we evaluated, and moved forward with the changes we made to our rules.

MS. ALLEN: Thank you, Mr. Nazemi. Mr. Pettit, do you have anything you would like to add?

MR. PETTIT: Well, thank you. When I was listening to V. John White's testimony earlier, I thought I might just come up here and say what he said, and then go out and have a beer and leave it at that, but I think that I will not. And I want to talk just a little about the background of the priority reserve case, and the larger implications both in South Coast and otherwise. What we are seeing in South Coast is a conflict, or a potential conflict between the demands of the Federal Clean Air Act and the need for more power, and cleaner power, in South Coast. Because the District is in non-attainment, which, you know, is not some kind of Buddhist term, but it means they are not meeting the Federal standards for a number of pollutants, including ozone and PM, if you are going to have a new source of one of those pollutants in the District, you have to get offsets from somewhere. And it is a market-based system, it was put into place in the 1990s, in the amendments to the Clean Air Act. It is a market-based system and the idea is very simple, when the price of the traded commodity, whether it be gasoline at the pump, or whether it is PM credits, when the price gets really high, the idea is that people in that market are incentivized to do something different. You buy a Prius, you drive less or, in the case of electrical generation in the District, you listen to Mr. White and you think about things like renewables within the existing transmission patterns, and the like, as opposed to just throwing more fossil fuel in there. And, in fact, the premise of this hypothetical, things got expensive, is exactly what happened. The market price in the market, if you could get PM credits, it skyrocketed. It was in the low six-figures per pound, and if you need, say, half of it for PM, and if you need half a ton, then you do the math and that is an awful lot of money that, at the end of the day, the project proponents will be asking that the ratepayers pay for. So that really got out of hand. But instead of taking the lesson that something different needs to be done, what the District did, supported by industry, is the District ran up here to Sacramento and tried to get the rules changed so it would not have to comply anymore with those rules, and then it could go ahead with business as usual in permitting, or helping to permit, these fossil fuel plants. And that is the SB 696 that we just heard about. I think we have different views on whether there is any liability to that, but I am not a politician and, at the end of the day, I do not pretend to know what is going to happen to it. The larger problem with it is that the Clean Air Act is a Federal law, and asking the State Legislature to deal with it, that is about as effective as passing the law here in California that says, henceforth, Arnold Schwarzenegger will be on the $5.00 bill. You can pass that, but it is not going to have any effect at all.

So here is where we are on the priority reserve litigation. When the District put this idea forward, we and a bunch of community groups said, you know, you are going to be bringing in more PM pollution just by way of this example, into the District than a multiple of the Port of Los Angeles, and you need to look at that under CEQA, and you need to look in particular at alternatives to just bringing in more fossil fuel, and what alternatives, for example? Well, what he said, what Mr. White said, is a good start, and they did not do that, and they said, "We don't have to. We don't have to do that." And then the State Court Judge said, "Yes, you do have to do it," and they got religion and they said, "Okay, we'll do it," and then they did an environmental review. But I thought, or we thought, it was perfunctory and unscientific, and the Judge we took that to agreed, and she said -- she did not say, "Your credits are no good," she did not say, "You can never give these credits away," or, "You can never sell them." What she said is, "Do a decent environmental review, look at what you are actually going to do, look at the…." She laid it out. She put a menu in her decision of what the District needs to do. That was a year ago, and they have not done it, there is no draft EIR even out yet, and when it is going to come out, I have no idea. And as soon as they do that, and they do that to the Court's satisfaction, the CEQA challenge will go away, and they can resume doing whatever they think they can do, subject to the issue of do they really have any credits, or are the credits phony? But that is an issue, the phoniness, or reality of the credits, is an issue that the Federal Courts are going to need to decide. And so, in the mean time, when you see these conflicting interests, the interest of the Clean Air Act -- the Federal Clean Air Act -- the interests of the environmental transparency analysis in California, and the interests in having more power and more renewable power in South Coast and otherwise, it is posited by many as a terrible problem you cannot solve. I am not buying that. I think there are ways to solve it, and if we listen to Mr. White and people who are very thoughtful about what the alternatives are to fossil fuel plants, and I do not need to lecture you folks about what those are, that is how I think we get out of this problem, both in South Coast, and throughout California, because the South Coast is not the only district, as you know, that is in non-attainment, that has bad air. The San Joaquin Valley, for example, where people are seeing those problems right now, and until we have a good handle on how to resolve all these conflicting interests, they readily, I think, a lot of these issues will be resolved in Court.

MS. ALLEN: Thank you. In the interest of time, I am going to move on with the questions and then, at the end, any of the panelists can weigh in on their thinking.

We are going to return to the sequence with number 1, "Is there any advantage to a repower project which could be provided with a long-term cost-plus contract per AB 1576 versus a green field project, an Energy Commission process as it exists today? Should there be in the future?"

MR. HARRIS: Thanks, Eileen. Again, Jeff Harris here on my own behalf to talk about this issue. I appreciate the invitation to the Commission. Given some of my recent interactions here, I am surprised I was let in the building, let alone invited, but I very much appreciate the opportunity to speak with you here today.

As I said at the top, we represent a wide variety of generators, some of them have once-through cooling, some of them are traditional gas generators, we also have some folks trying to do some of the large solar projects that were alluded to earlier, and so I bring a pretty diverse background to this discussion, and that is part of the reason I am not speaking on behalf of any one client. I guess the other thing I would note, too, is that we do some work for the WECC, the Western Electricity Coordinating Council, and so reliability is first and foremost in my mind when I first start thinking about generation issues, and it is pretty incredible to think that we are sitting here talking about knocking out 30 percent of the in-state capacity, given that we import about 40 percent of our energy needs in California during the peak. But in terms of the question, and whether it is an advantage for these projects moving forward in the Energy Commission process, I am lawyer, so I parse the words a little bit, and I guess I want to note one thing, which could be provided with a long-term contract per AB 1576, I understand that issue is still outstanding at the PUC and we will be looking to see how that might get resolved. I tried to think of what question my advantage is and, really, the Energy Commission project is a siting process, and you are looking at potential environmental impacts and compliance with laws, ordinances, regulations, and standards, and I will not say lores, I picked up on that. So what kind of advantage could a project be provided? And, really, the only advantage I could think of would be an expedited permitting process. Well, the answer to the first question, directly, no, there is nothing -- the Energy Commission process as it exists today does not allow any special advantages to these projects moving forward. It is simply the case. And if you look at the statute closely, there is actually not a way for the Commission to prioritize even, say, renewable projects over gas projects. I heard in the ether a little bit -- something a little bit different than that, but as a matter of law right now, as the laws exist, there is not any way to expedite these processes. The Energy Commission provides that they will essentially bring these in first come, first serve, there is a reason that they give them a docket number, which is the year and then the number it came in the door. So that is the way existing law is now and I do not see that changing.

In the future, should there be any changes? It is a very interesting question because we start looking at all these policies you have been wrestling with all day. There is a clear relationship between generation and load and transmission, and so this Commission only has jurisdiction over one of those things, and I would hate to see a siting case that involved a power plant and a Sunrise Power link because I know I would probably be retired before that would be finished, and so I am not sure that the Energy Commission alone can solve those problems. I am also not eager to go back to centralized planning where the state decides where projects should be, how big they should be, and where they are put. So the law, in my view, the way it is fine, it really is more a question of resources. I think it is quite ridiculous if you are being asked to do what you are supposed to do in terms of siting cases with three furlough days and a lack of other resources. I would like to see all of these projects move through more quickly. I am a firm believer in that California ought to control its own energy destiny, as opposed to being an importer of electricity. If you want to talk about greenhouse gas and greenhouse gas portfolio and what the profile of California's generation fleet is, if you were a net exporter of power, if we had more generation than we consumed, we would know exactly what your greenhouse gas profile looks like, and you would be able to control it. And so, if there are going to be any changes made in the process, I would like to see expedited those processes, I would love to see a project done in the statutory one-year time frame, it happened once in 1998, that I recall, with a case that I was working on. And part of that may required the Commission not to change the law, but go back and look at how it processes these applications. We do wind projects, we have done other large industrial projects in California, and none of those projects had the scrutiny from the environmental perspective that the power plant has in California. And in some ways, the Commission has tapped its own resources by really over-analyzing these projects, in my view. You cannot tell me that every other project that is CEQA compliant, that does not do the same detailed level of analysis that the Commission does, is somehow not approved pursuant to CEQA. And so I think there are ways, short of changes in the law, to try to move things along more quickly. And I guess in the interest of time, I am going to stop there.

MS. ALLEN: Mr. Comnes? NRG is the owner of a green power project, El Segundo. So do you have any succinct thoughts on this question?

MR. COMNES: On the 1576 question?

MS. ALLEN: Whether there are any advantages to a repower project versus a green field project in the Energy Commission processes that exist today, and whether there should be in the future.

MR. COMNES: You know, obviously we believe that the repowers and brown fields offer a lot of factual or situational advantages. You know, it is worth going back to 1576 and reminding ourselves what was required to be a 1576 project, it had to use existing transmission natural gas rights of ways, it had to be more efficient, and so these are obviously positive attributes that would work well with any -- with the Commission's existing processes under CEQA, or the Warren Alquist Act. So I do not think we are asking for a special process, other than, you know, the project, as Jeff said, a project has got advantages and the Commission needs to not over-analyze things and get the project through. There are obviously some very pressing mandates out there that need to be addressed, and in this case today, we are talking about once-through cooling or 316B agendas.

MS. ALLEN: Thank you. I would add that we often hear from the coastal communities where the once-through cooling facilities are currently located, and I am not aware of any that are embracing the idea of a brand new power plant right on the coast.

MR. COMNES: I -- well, I am sure they are out there in the ether and they will speak up -- well, actually I do not want to -- we have an open docket on El Segundo, but I would say we enjoyed pretty good support from El Segundo. And I will leave it at that.

MS. ALLEN: Thank you. That brings us to Question 3, "Please discuss the advantages and disadvantages to alternative sequencing and Energy Commission permit, followed by a power purchase agreement, or a power purchase agreement, then an Energy Commission permit.

MR. COMNES: You asked me to address this one first. I keep wondering if this is a trick question.

MS. ALLEN: No, not intended.

MR. COMNES: Okay. Short answer is we want to see the PPA first, I mean, again, NRG has done them both ways, we have had a docketed -- we had a permit for the El Segundo repower, it is going through some permit modifications, but that docket and permit has been in hand -- the docket has been in place for about a decade, the permit has been in hand since, I think, 2005. Obviously, we have been willing to take the risk to get a permit in advance of PPA. Alternatively, we have done repowers where we got the PPA and had to scramble to get the permits and get it built in a little over a year. So we are capable of, you know, all means necessary to pursue our core business, which includes repowering our sites. That said, I guess a lot of advantages to having the PPA in hand before embarking on the permitting process in California, it has always been an issue, but it is even more of an issue since last November. The financing is an extremely big issue, and so lining up, you know, for Management willing to line up, risk capital and development, and to structure a project, it very much helps to have a PPA in hand. And then, you know, second, I will just observe, is that so many of the environmental agencies are looking to having the PPA in their process of prioritizing projects. It is obviously a part of the Air District's criteria, the priority reserve is predicated on having a PPA or some other proof that it is being used for local load. And I do not know Chapter and Verse, but I have seen it sited in the Energy Commission and the Water Board proceedings. So I think the answer is easy, and that is I think the RFO process, as I spoke earlier in Panel 1, the RFO process should start it, but have sufficient flexibility to allow for a bumps along the way in terms of getting environmental permits.

MS. ALLEN: Well, we are heading right towards the time that it was originally allotted for Panel 4, and Questions 4 and 5 could have quite a few ideas.

COMMISSIONER BYRON: You go right ahead. You have another half hour.

MR. HARRIS: Could I interject something on this question before we move on, real quick? I guess I would want to call the attention to the Public Utilities Commission the recent proceedings here at the Energy Commission on the Tesla license extension, and to answer the question, I think this is as much a procurement issue as it is an Energy Commission issue. A Power Purchase Agreement, or not, does not affect the environmental review that the Energy Commission performs, and so it is a non-issue in a siting case whether there is a PPA or not. So, to me, the trick of the question is I do not know why it is asked, but it really is irrelevant to the Energy Commission's review. But I wanted to point out for your attention that the PG&E Tesla case, PG&E seeking five additional years to build that project, and their main argument in favor of five years versus one, two, or three, is that they want to participate in their own procurement cycle. They are looking at needing five years, in their mind, to potentially change some rules at the PUC, and also participate in a cycle that will start, I believe, next

January. So there is a long lead time that is associated with those procurement cycles; it does not line up very well with the Energy Commission's five-year license, and it is something that I would hope the two Commissions could talk about, but inter-aligning the procurement process, which -- and by the way, for my independent generators, I do not think we got five years from PPA to actually build a project -- but I think there might be some way to better align the two Commissions' processes so that your license term and your procurement process actually do line up in a way that allows people to move forward with their projects.

MR. NAZEMI: Eileen, could I also add 30 seconds to that? I think, in my mind, the reason that question is probably being asked is to address whether or not a power plant, and you heard today and all along about concern with fossil fuel fired power plants being added, the capacity is needed, but what kind of power plant is the question. I think the reason for this question is whether or not there is really a need for that power plant to be built, and so the Power Purchase Agreement does put a little bit more certainty that, yes, it was needed, there was an RFO process, it came in front of the PUC, and it was approved to be granted, the Power Purchase Agreement. So that -- I know it does not satisfy completely the question of whether or not we need more fossil fuel power, but it does address it to some extent, I think.

MS. ALLEN: Thank you, Mr. Nazemi. Something that does not really come out specifically in terms of the Warren-Alquist Act, but nevertheless, we hear about it often, is questions of need for specific power plants, particularly in the community setting when we have public workshops and hearings, need questions often come up So your observations about the relevance of the Power Purchase Agreement in that question are helpful. Barring further comment, moving on to number 4, "Using the terminology of the Joint Energy Agencies Proposal for Once-Through Cooling Retirement, given the analyses as embodied in Step 2, and eventual decisions that will be made in Step 3, should the Energy Commission siting process attempt to ensure that new power plants have the necessary operating and environmental characteristics to replace those of OTC capacity that is retired?" This is a bit complicated, but -- particularly the second part of the question, you know, what next in terms of replacement for OTC's capacity? So, Mr. Pettit, would you lead off with your ideas?

MR. PETTIT: Sure, I will take a run at this. I actually view Questions 4 and 5 as alternatives of the same question, and have kind of the same attitudes towards them, is that the questions have assumptions built in that I think are backwards, that instead of looking at what technology do we have, and what to replace that with, I think it is better to look at what is our demand going to be, and how can we best fulfill that within the values, whichever values are brought to bear. Ours would be, I mean, you have heard this a million times, ours would be, let's start with energy efficiency, what can we get from that, move on to renewables, what can we get from that, before we start going down and talking about which piece of steel should we -- which piece of metal should we replace with which other piece of metal. So I would approach both of these questions differently than the way they are posed, and would say, as I just mentioned, that I think we have it backwards, and we need to look at demand first, rather than looking at replacing metal first.

MS. ALLEN: Okay. Are there any comments on question four from the other panelists?

MR. COMNES: I will just comment that, I mean, I believe the states heavily embrace the loading order concept that is part of the energy action plan, and so I mean, you only have to look at the last LTTP Order to see how hard, just how clearly the Commission worked to make sure that they met loading order objectives before they found some net residual need that they would release to an RFO, to procure fossil generation. So I would challenge anybody to just go back and read that decision in terms of how they went through and loaded up on energy efficiency, renewables, cost-effective distributed generation -- am I forgetting anything -- and then, you know, looked at remaining fossil capacities as a way to meet the load requirement and the requirement to replace once-through cool generation due to a very oppressive retirement assumption that was in that order.

COMMISSIONER BYRON: Mr. Comnes, I am glad you brought this up. Mr. Pettit, if we could just go back to your comment for a second, I am a little bit troubled by it, and maybe we are not doing a good enough job. You are conveying the fact that the loading order is the law of the land, and the efforts that these Commissions have been putting forward to pursue energy efficiency and renewables -- am I to understand from you that we are not doing nearly enough?

MR. COMNES: That was not the intent of my remark. What I meant to say, or the point I meant to make is that, to me, question 4 and 5 have assumptions built in that, if some current projects go away, how do we, without really thinking about it much, we need to just replace them. And I think that that assumption is incorrect.

COMMISSIONER BYRON: No, I think what those questions are asking, if given that energy efficiency, all economically achievable, given the demand response, given that we are pursuing a high level of renewables, then how do we address the characteristics that those existing plants have that we are interested in having on the system in order to accomplish these other goals, namely integration of high renewables, etc. So starting from that point, please answer the question.

MR. COMNES: Right, well, I think, if I understand you right, instead of by "new plants," you mean "to come," not the plants that are being, you know, taken off line, or whatever, the OTC plants that are being retired, and having gone through all of the other things that you said, I think that actually the CEC has done a robust job of looking at the environmental consequences of putting in fossil fuel plants wherever they are proposed to be put in, and in terms of the question about looking at the environmental characteristics, that is what I took that to mean, and in terms of -- this may seem not coming from me, but in terms of looking at the air quality, in particular, the air quality aspects, you know, our issues with the District are not that they do not have the technical expertise and the inclination to do that. We have legal concerns about whether there are credits available such that, at the end of the day, they actually have things to either give away or, you know, give away to the essential public services, and the like, or sell to the power plants. It is not that the district, as I say, does not have the technical capability of telling the CEC, "Well, yes, these people need the Clean Air Act," or, "Those people don't need the Clean Air Act." So I am not really suggesting that we need some kind of vital change in the way that those substantive matters are now handled, as between the Air District and the CEC. Does that respond to your remark?

COMMISSIONER BYRON: No, but I am kind of dense, I guess. How do we replace the ramping, the firming, the load support, the auxiliary services, the kind of capabilities that these once-through cooling plants provide on the system? How do we meet -- there is another Federal law that we are talking about here today --

MR. COMNES: Right.

COMMISSIONER BYRON: How do we meet that law and have the capabilities that we are going to need to operate the system at the higher integration of renewables, etc.? And that is the question we are trying to get at, and I am not sure that we have an answer for it.

MR. COMNES: I personally do not have an answer for it. I am basically an air guy and air quality guy, I can get you an answer from people who would know that, but I am not the guy.

COMMISSIONER BYRON: No, you have got everything tied up in court and that is probably a good part of the reason why we are all here today, is we are trying to figure this out. So --

MR. COMNES: Well, I do have an answer for that one. I think that one is easy to answer. The part that is tied up in court is that the District needs to do an Environmental Impact Report that is not a joke. They have had a year to do it, they have not done it, someday now, we will get a notice in the mail that the Draft EIR is out, and we will take a look at it, and if it is decent, then the Judge is going to bless it, and then this little so-called moratorium will go away; if it is not decent, then we are going to have more tsuris, if you will, more grief, in the District because the moratorium will probably be continued. And at that point, I think the Governing Board, or the District, needs to take a hard -- would need to take a hard look at just what it is that its staff has been doing for the past however many years to comply with what I think is a rather simple laundry list of tasks that the Judge has set out for them to do in terms of their environmental review. You know, CEQA is not rocket science, you just have to do a decent analysis of the project that is before you and look at realistic alternatives, that is really the heart of it. And it should not take more than a year to get that done.

COMMISSIONER BYRON: Okay, thank you. Ms. Allen.

MS. ALLEN: Thank you.

MR. NAZEMI: I would like to add something, Commissioner Byron. I think --

COMMISSIONER BYRON: Gentlemen, you know 34 years of marriage, I have done a lot of marriage counseling, and -- I mean, for me -- and let's just accept each other's viewpoints here and acknowledge, you know, we all have our own perspectives, okay? So, Mr. Nazemi, I hope you do not feel you have to respond as though you are in court.

MR. NAZEMI: I do appreciate your comment. I was going to actually go back to your comment about the loading order because that is what our agency felt was needed in order to determine whether a power plant was really needed, fossil fuel fired power plant was really needed, because that loading order that goes through the state agencies' process does look at all the factors that you indicated, the energy efficiency, demand response, renewable, and then, at the end, if you still need that power plant, then it comes back that, okay, now can we approve this process? And I think it is important to point out that question four deals with what other alternatives should be used, and I will wait until you get to question five, but in terms of question four, I think it is important that our agency did not feel that, just replacing what is there with what was there is enough; we felt that something needs to be there that is better than what was there before, and the longer this process takes, and I do not want to turn this into a debate because I disagree with a lot of the statements Mr. Pettit is making here, but the longer this process went, look at the realistic view of the older, dirtier power plants, not just once-through cooling, but the other fleet is going to stay in place. We are not shutting them down, they are staying there, they are operating. So if you need to ramp up, you are going to use that. Now, if you had a replacement with a cleaner, more efficient power plant, that you could ramp up, your emissions are going to go down, they are not going to go up --

COMMISSIONER BYRON: Thank you.

MR. NAZEMI: -- but that is a different --

COMMISSIONER BYRON: No, you characterized the problem very well and that is why we are here, and we are all keenly interested in accomplishing all of these objectives, and you are both important stakeholders in this process going forward.

MS. ALLEN: Thank you. We have had a spirited exchange, stimulating and provocative. Since there has been a bit of bushwhacking, Ms. Phinney, do you have anything to add to number four from the League of Women Voters of California's perspective, which is process oriented?

MS. PHINNEY: Well, I am glad you mentioned the process because the League's mission is to promote the active informed participation of citizens in government, so I do have some overall remarks, and they do reflect on process, as well. And I would first like to thank the agencies for holding this workshop because the League actively promotes open and transparent decision making processes that involve multiple stakeholders, so obviously you are doing that. The League does have an energy position which we updated in 2007 through member study and consensus, and I believe that both our overall position speaks to the issues that need to be considered when looking at something as complex as once-through cooling, and then we do kind of get down to the nitty gritty of certain factors that should be considered when evaluating new resources. Our position states, in brief, that the League supports development of state energy policy that will ensure reliability of energy resources and protection of the environment and public health and safety at reasonable customer rates, giving primary consideration to conservation and energy efficiency and renewable resources. We do not have a position on once-through cooling per se, that would involve detailed study by our members, and we seem to be diverted to budget and legislative issues at the moment.

COMMISSIONER BYRON: Good. I am glad somebody is.

MS. PHINNEY: But in acquiring new energy or electric resources, our position indicates that factors that we think should be included are reduction of greenhouse gas emissions, developing and deployment of renewable resources, contribution to the diversity of the resource mix, availability at times of peak power demand, support for base load power requirements, and protection of public health and safety. And when considering repowering or green field sites, we think these factors should be evaluated. We also think that the state agencies should be considering the land use objectives and plans of local governments, as you look at the various options in front of you, and whether green field, or repowering, it is going to happen somewhere in some local government's backyard, and we would encourage the energy agencies to communicate with local governments throughout this 11-step process, and particularly provide information that is related to reliability issues in their specific areas. And while I have the microphone, I will also touch briefly on number five which, again, is probably a much more detailed question than the League's position would allow it to respond to. But I would point out that there are very strong views that have been put forward, that say rooftop

PV will solve all of our problems, meet all of our energy needs and goals, and equally strong views that say renewable energy in the desert and new transmission construction will meet our energy needs and goals, and we think the public is confused by these messages that have not necessarily been resolved at the state agency level, so we would encourage the state agencies to tackle this directly to make determinations that will inform the public process and debate as we move forward, and we think that the Energy Commission's Integrated Energy Policy Report is a very good vehicle for that. Thanks.

MS. ALLEN: Thank you. We have somewhat smoothly flowed into number five which is, "What are the most environmentally and economically feasible technological alternatives, if any, to gas-fired generation for OTC replacement? Please discuss the generation options, both distributed and centralized, that you think will be available and practical within 10 to 15 years, assuming similar air quality restraints in areas such as the South Coast Air Basin." Now, I formulated this question and I had in mind items like the number of remarks I have heard that there is no need for a proposed fossil fuel power plant with a certain amount of capacity because options like rooftop PV should be able to take care of that, and should be a much higher priority in terms of the Energy

Commission activity. So I am wondering whether there is something like a credible, specific roadmap out there that would lead to a plan for much greater implementation of rooftop PV, for example, in an area like the Los Angeles Basin, and then, you know, how much could we expect it to contribute versus something like a gas-fired replacement option? So I am looking to hear pretty wide-open commentary here. Go ahead.

MR. PETTIT: I do not want to have again the discussion we just had, but let me just say something about the phrase here, "similar to air quality constraints." I actually think that, although the district has been doing a good job in cutting down, for example, on the ozone, in particular, because about 80 percent of the ozone problem in the District is from mobile sources, I think that despite the District's best efforts, we are going to have at least as bad issues and possibly worse, given how the District and the State propose to meet the Federal rules or guidelines within the date that they are supposed to meet it. So I think that, in terms of the strictures the Federal law may impose on the South Coast, as years go by, that things are going to get worse, not better, and that the conflict -- the perceived conflict that we see now between the Clean Air Act and the need for additional fossil generation in the Basin is going to get worse, not better, over time.

MS. ALLEN: Well, following up on that, what kind of mechanisms that are in place now would it take to see a lot more rooftop PV in widespread warehouse areas like Ontario? When you fly into the Ontario Airport, you are faced with a sea of roofs, and it is often a very hot day there, so, simplistically, you know, what kind of contribution could rooftop PV make that is above and beyond what is occurring now?

MR. NAZEMI: I think I can address this briefly. Part of the process deals with economy and cost-effectiveness, and I think there is clearly a movement towards making these more cost-effective and, as a result, one of the criteria that we have actually established, that if the power plant uses our credit was that the money we get, a third of it will be used for rooftop solar, and it would be done in the area where the power plant is going to be built, so it will reduce the need, it would provide the communities with the money that they need to put in these installations, so they do not have to pay for it, it will be paid by the power plant proponent. But when we talk about distributed generation, I would like to point out, in terms of some of the existing technologies that have been used in combined heat and power, even reciprocating engines, when we look at emissions that will come from the reciprocating engines, even a combined heat and power, and compare that to the centralized power plant, we see that the emissions are sometimes three times higher from a distributed generation unit. So unless we talk about more advanced technologies such as fuel cell and other types of technologies that result in lower emissions, I think it is, again, a misnomer to say that we do not like central power plants because of the bad air quality, but distributed generation is okay. In fact, distributed generation will contribute to ozone three times more than a central power plant would, and if we are worried about the fine particulates, it is typically distributed generators that have much lower stack heights, and the concentrations of particulates will be greater at the ground level compared to a very tall 200-foot stack of a power plant. Now, again, I am not suggesting that power plants are the best way to go, but when we talk about distributed generation, I think we have to frame this, that not every distributed generation is better than central generation.

MS. ALLEN: Thank you.

MR. HARRIS: Eileen? I guess a couple things that bother me as I sit here listening, and I did not want to get involved in the earlier brawl, so I did not say anything. The question of need keeps coming up, do we need this power plant? Is it needed here? Is it needed there?

And that -- I find that terminology very alarming, for someone who works in the power plant industry, and the question of whether a project is needed or not. As I said before, we are a net importer of electricity, so if you just want to do it on "how many Megawatts do we need in California," every project that is going to be built is needed. I guess the other thing that bothers me about that terminology is that, at least in the merchant setting, there is no public money at risk for a project that is trying to be developed, and believe me, you can look at some of the recent bankruptcies to see that that is the case, there are millions of dollars spent in developing these projects, but it is not public money that is being spent. So if you want to argue a need for a project, to even want to license or certify a project over here, just "do we need it," there are public resources that are going into reviewing those projects, I already acknowledged that, there are also some fees that are paid that maybe should be a little different, but the whole question of need, I think --

COMMISSIONER BYRON: You mean a little higher?

MR. HARRIS: You know, they ought to be reasonable. If I get what I paid for in a full [inaudible] [1:16] decision, oh, yeah. I will be glad to pay for it. So, you know, the whole question of need, to me, it is really a strongman in a lot of respects, and part of the reason for that is that, if you build superior projects with higher heat rates, one of two things is going to happen, either they are going to displace a unit that we are not tearing down, I acknowledge that, but they are going to displace it, and you are going to get the same amount of Megawatts for fewer air pollutants. Or the other thing is, if it is not needed, it is not going to run. There will be zero environmental impacts with it. So I see the whole need argument as really something that you ought to set aside, certainly in the merchant setting, it is something that -- if the project is not needed, it is not going to run and it is not going to have those impacts, and so I really do not think you should be focusing on that issue in this discussion, in the debate.

COMMISSIONER BYRON: Mr. Bohn?

COMMISSIONER BOHN: I would like to ask, then, what concept you would substitute in its place. Need is the sum of an evaluation of policy objectives, cost benefit, technology, and the rest. If you do not utilize the concept of need, what would you do? Like it? Want it? It's pretty? What would you put?

MR. HARRIS: Well, I am not suggesting that the PUC should not continue to try to handle the needs of the utilities to serve their ratepayers, that kind of analysis makes sense, then you fold that into a procurement process where those resources are procured, but the idea that you could say any project is not needed, at least when there is a merchant facility involved, to me, is nonsensical because, as I said, they will not be built or, if it is built, it will run and displace something else, so I think you ought to keep a very close eye on the IOUs and what they are doing, and what they are planning to develop. They have asked for reimbursement for their development costs, which merchant facilities do not get, and you ought to be very cautious about providing that kind of reimbursement to them.

COMMISSIONER BOYD: I just want to follow-up on this need exercise because I think it is a little simplistic, if I may suggest, when you say, "If it is not needed, it won't be built," one can look around the state and find all kinds of silly things that have been built that, in some way or another are not [quote] "needed." Needed is a function of time, it is a function of particular circumstance, it is a function of forecast, it is all those things. I am okay with an alternative concept, but you seem to want to do it on a plant by plant basis, and I guess "need" is really a systemic kind of thing. One can say you do not need any particular plant until you shut down the one that makes the lights go out.

So I am troubled by your sort of short shrift of the concept of need. I would argue quite the converse, that a balanced and systemic view of need is, in fact, the right focus on these kinds of discussions.

MR. MANSOUR: If I heard Mr. Harris right, maybe that is a missing point, he is talking about total [inaudible] [4:38], someone was not asking for recovery from, you know, their [inaudible]. There is no risk to the ratepayers, just like someone building an apartment building [inaudible] and take the risk whether they find tenants or not, compared to a government building where you need [inaudible] of government or not because it is the taxpayers' money. So I think the difference, this is the difference we are talking about. So if someone is putting their money at risk, either it is needed to replace either imports that we know -- 20 to 25 percent on average, and they represent about half of the contribution to emissions. So if you think your point is if you build something at risk-free from the ratepayers' point of view, that would replace that. That is a good thing, and if it does not run, then it does not pollute. Is that your point? So I think the distinction between the need from a pure investor point of view compared to an IOU who is expecting the recovery is worth looking at, that my question to you is, how many investors these days are willing to actually go

100 percent merchant?

MR. HARRIS: As you know, not many. It is a very expensive process. You have to get a hold of the land, some that are optioned or otherwise, and this process of licensing California thermal power plants is a multi-million dollar venture, and what you are hoping for at the end of the day is a license that you can use to bid into an RFO to actually pay back your investment. So you are seeing fewer and fewer folks doing that. I think that one of the things this Commission has to acknowledge, too, is that there are going to be more gas projects, I do not think natural gas is a very -- two words -- it is the kind of fast starting, flexible stuff you are going to need to be able to integrate renewables into the system. And so I understand and appreciate the emphasis on renewables, and some of my clients very much appreciate that emphasis, at the end of the day, I think natural gas -- at least over the 10 to 15 year horizon that is talked about in the question, is going to continue to be an important part of making sure the lights stay on.

MS. ELLEN: Thank you. I have received a discrete signal that we need to move on. So thank you very much for participating as panelists, and offering us your insights and views.

COMMISSIONER BYRON: Ms. Allen, thank you. And thank you to our panelists. People would have to wonder why is it that you have time to be here and share this panel given that you have 27 power plant siting cases before this commission and many more on the horizon coming in. I do not expect you to answer that, but do you want to respond?

MS. ALLEN: I will have to get back to you.

COMMISSIONER BYRON: Well, I have a comment that I would like to end the panel with. We appreciate your input very much. As you can tell, the work load is rather high right now in this Commission; we do not see that going down any time soon. But I would like to respond directly to some additional comments Mr. Harris made early on for the benefit of everyone here. Past is not prologue. The assumption that this Commission pre-judges or will move through CEQA on your time schedule is incorrect. It is becoming very difficult in this state to site these applicants -- to fully mitigate and site these applications. So I want to make it clear, this Commission will not be shortchanging CEQA to meet the applicant's schedule of requirements on any projects going forward. Given that, and the comments we heard today, you are not making it any easier for us. So thank you very much to the panel. And we look forward to the next panel, which we are going to transition to very quickly. And I apologize, I am just going to continue right through the break, we are not going to take a break here, we are going to go right to panel 4, and Mr. Hesters, if you will approach the podium, and if the other panelists will go ahead and please be seated, we will go right into our discussion. Mr. Simpson, I am not going to recognize you at this time, we are moving on to the topic before the panel.

MR. SIMPSON: Thank you.

Agenda Item 7: Panel 4: Changes to California ISO And Other Balancing Authority Transmission Planning Processes

COMMISSIONER BYRON: Mr. Hesters, you may go ahead and begin in the interest of preserving time and we have so many people that are here, I want to make sure that we are respectful of that.

MR. HESTERS: I was sort of counting on the break for some coffee, but I will try and stay focused. We are missing Pat, and so she will be here -- let's give her a few seconds to start.

COMMISSIONER BYRON: Please proceed.

MR. HESTERS: The sort of purpose of this fourth panel is, so far, we have really looked at generation and the characteristics of generation, and permitting generation, and paying for generation. We are now turning to transmission alternatives to generation and how we go about identifying and planning for potential transmission alternatives to once-through cooling generators. We have a panel of four. One the far side, we have Mark Esguerra from Pacific Gas and Electric; next to him, we have Mo Beshir from Los Angeles Department of Water and Power; the empty chair is Pat Arons from Southern California Edison; and then we have Laura Manz from the California ISO. The panel, we sort of structured around five questions. The firs three questions are sort of focused on transmission planning processes, those -- the first two that come directly from the joint energy agencies proposal, the third one talking about length of time and data needs. I am going to break this up into sort of talking about the first three questions, then, we will talk about the fourth question, which is looking at the approval and permitting process for transmission facilities, and finally, to the fifth question which is how the Edison and LADWP -- Southern California Edison and Los Angeles Department of Water and Power, because the two areas are essentially right around each other, could somehow coordinate to deal with once-through cooling transmission needs and generation needs. So let's start with the first, sort of first three questions, in general. Mark, since you are on the end, let's start with you.

MR. ESGUERRA: Okay. As Mark mentioned, I am Mark

Esguerra from Pacific Gas and Electric Company. The first question I had was on commenting on the Step 2 of the Joint Proposal and if it identifies the necessary studies.

COMMISSIONER BYRON: Mr. Esguerra, is your microphone on?

MR. ESGUERRA: It is on now, sorry. So response to the first question, and my comments, looking at Step 2 in the Joint Proposal, it appears that it does have all the necessary studies identified, it does it actually really well. I do see linkages between other transmission planning processes such as the Renewable Energy Transmission Initiative, as well as the Transmission Planning Process, it also does have some tie-backs to -- it emphasizes not only looking at what the local requirement and impacts are, but as well as from the entire system. So I think it does a decent job in covering that. One thing that I would like to see a little bit more vetted out would be some of the discussion of how the other utilities -- the transmission planning organization utilities, how they can get more involved in looking at this process, participating in it, as well. And obviously, the devil is in the details in some of these items, from a high level, it looks like it works, making sure that we continue to show the integration throughout; with all the different initiatives going on, it is going to be a challenge.

MR. HESTERS: I sort of made a mistake here. Let me give a brief overview of what is in Step 2, just in case you all have not read it or memorized it. In general, it is an extension of the current local capacity requirement studies, basically taking a one-year study and extending it out over 10 years by escalating loads, projecting future resources, projecting future transmission, projecting energy efficiency, and demand response, and local generation -- not local, but distributed resources. It is essentially a spreadsheet analysis, it allows you to look at a number of different scenarios, generation alternatives, transmission alternatives. It is not as detailed as sort of the one-year study that is done with a power flow analysis, but it does give you an idea of what is needed in the long-term. Let's -- rather than go -- let's go with Pat first, and then we will go to Mo on this question.

MS. ARONS: Which question?

MR. HESTERS: We are working on Question 1, oh, actually, sorry, let's have Mark continue on the second question which has to do with the Step 7, which is basically folding in the once-through cooling policy requirements in through the ISO annual planning process.

MR. ESGUERRA: Okay, so my take on that is that the existing transmission planning process that the ISO set forth has the framework to accommodate this. I think it has a portion of the process where you are setting the assumptions, as well as allocating time for studies, as well as accepting proposals for either transmission or for non-transmission solutions. However, I think it can be a little more revamped to provide some special focus on this area. As I mentioned before, there are a number of other initiatives that are also participating in this, and without this special focus on the OTC, I am afraid that some of the work that is undertaken in a transmission planning process can get lost in terms of where this lies in there. Another thing that I point out is that some of the solutions here in maybe the larger spectrum, it could take multiple planning cycles if it involves other alternative load within transmission when we are trying to weigh and vet out the differences between the two.

MR. HESTERS: Yeah, that was the second part. How would you sort of look at generation alternatives to transmission? Because the existing process does not really look at generation, it sort of takes generation from a proscriptive view in that generators that are under construction are included, generators that are not under construction are not included.

MS. ARONS: Okay, this is Pat Arons. I am with Southern California Edison. I think there are a few missing pieces in the recommendation in Step 2, and that is, it is focusing on load pockets, if you will, and focusing on the question of how much capacity might be needed to be put under contract, to reliability serve that load pocket. But I do not think it really goes to the methodology that you need to begin to use to shut down on a permanent basis once-through cooling generation. You do not get an examination of the stability issues, you do not get an examination of loss of import capability, and so there are some missing pieces there. So I think there is some expansion to some of the tools that are used, and I think there are some new methods that we maybe need to develop that are specific to examining the questions on once-through cooling.

MR. HESTERS: Just as a follow-on to that, it does not seem to me like even the current local capacity requirement studies encompass some of the -- they do not really deal with the stability issues so much, and they also do not deal with the import -- changes in imports, as thoroughly as we would need to look at once-through cooling. Is that sort of where you are leaning?

MS. ARONS: Yeah, I think -- yes. I think it is a slightly more detailed kind of technical study that needs to be done. I think the LCR tends to focus on the end product being a capacity contract, potentially, somewhat like the old LCR, RMR type contracts that generators had, where we had reliability issues related to the grid. I am not sure the value of going out one year or 10 years if your focus is on a reliability contract. For example, on the old RMR contracts that we had with the ISO, they were evergreen contracts, and you had to propose a transmission upgrade to eliminate the contract. I think that might be a model that we follow for a business of managing the shutdown process because, frankly, transmission is a very long lead time item that is going to take 10 years or more to get built. You want to have some sort of security knowing that the generator is not going to shut down while you are working on a potential solution.

MR. HESTERS: Okay, and then the next, we are sort of going through question two, as well as kind of a general -- they are both related to the planning and changing in the planning process, and Step 2 is basically --

MS. ARONS: Do you want me to comment on that, as well?

MR. HESTERS: Yes.

MS. ARONS: I think what is important about the studies that we do, that we do not capture in the current LCR studies is that we need to broaden the study basis to be all of California utilities, so the publicly-owned utilities, in addition to the investor-owned utilities under the ISO would have to be brought into the study mechanism. And so I think the ideal venue for doing that is this newly developing California transmission planning group, where all of the pertinent entities are at the table, we are talking about, in fact, a study plan for doing the studies jointly because many utilities have generation that might be at risk for shutdown, and so you have to look the system on an integrated basis. So I do not think the LCR process alone is the right venue, I think it is a slightly different venue and it has more utilities there.

MR. MANSOUR: Mr. Hesters, did I hear you suggesting or claiming that there are a lot of studies that are being done now [inaudible] [20:21]?

MR. HESTERS: No, I was trying to sort of build on -- they do, I know that is the case, but --

MR. MANSOUR: Well, you said you thought they were -- I just want to correct the record -- that they all were in trouble.

MR. HESTERS: Okay, good.

MR. MANSOUR: They do.

MR. HESTERS: I know they do. I mean, the enhanced LCR was not going to do any stability. The enhanced LCR did not include that.

MR. MANSOUR: Well, just to set the record, LCR is a technical locational -- it is a coalesced thing that talks about a lot of stuff, to say it is reliability is met or not. So maybe --

MR. HESTERS: No, that is fine.

MS. MANZ: I was trying to wait my turn, but it might be time for me to jump in. So let me support exactly what you are saying, that the LCR needs to be taken in the context of everything else that is being done. And so it starts with, sort of having everybody in one balancing authority, which would be the happiest day, I think, for the State of California, to say we are all operating together, we are planning together, we are interconnecting together, we have something that looks like not necessarily integrated, but collaborative and coordinated. And so that is kind of where we are trying to go. If I can take a minute and just talk about the pieces of that, because I think that is the point that Pat is trying to make, and also the point Yakout is trying to make, is that the LCR is one of many things that informs the planning for the State. So we start with -- especially for the ISO, we are the only entity that has a fourth-quarter 890 compliant planning process, so we have that -- it is sort of on its own little track now, and it does all the stability and, you know, we look at all the technical things you need to plan a power grid. So it starts from a basis of technical soundness, let me just start with that. And I think that is the point Yakout was trying to make for us. And then LCR is one of many things we study within that. And so we are looking at a transmission system, and so that is sort of an important notion that we try to hold in our heads as planners -- we are planning a system. And as you take each element in a system, such as an individual power plant that has a once-through cooling, you would want to look at how is that impacted within the whole system. And so we can talk about, is there a transmission solution, and I think I heard earlier that there might not be a solution, well, there is always a solution; the question is how do we find the most cost beneficial solution. And so that is the next piece of the ISO planning process, if I could just say, I am answering question two, right now, is to say, yes, we have those things in place. So we have the Order 890 transmission process, we have a methodology to say, what are the ways we evaluate competing alternatives? And so we would have an economic assessment, a reliability assessment, look at does it provide the right technology at the right cost. So that is already there. And I would suggest, also, that within the ISO processes, we do this through an open, transparent, informed stakeholder process, so everyone is invited to show up to say, "Here is what we need you to look at," or, "We don't agree with the approach you've taken, we would like you to try it this way." So I think those are some of the sort of backbone pieces. We are taking this and stretching it with all the environmental considerations to a whole new level. I mean, we started with the Renewable Energy Transmission Initiative to say, how do we move the planning process forward to really study some of the harder problems? It is planning unlike we have ever done before. This once-through cooling exercise, I would suggest, has sort of similar needs to it because it does need collaboration, it does need everyone at the table, it does need all entities that are trying to plan a power grid in the State of California, to get together and look at what is the best way to do this. Given that we have moved back from this being all one big energy balancing authority, the answer is we are going to do this through the planning process, and that is pretty standard at FERC, also, we are seeing that because they have not mandated big large power pools, but they have said, "You need to coordinate your planning." And so we have the California ISO planning process, which then works within the California transmission planning group to say, "How do we plan for the needs of the State of California?" That, then, fits within the Western Energy Coordinating Council, which you might have also heard called WECC, but I got the no acronym admonition, so I am on that plan, and so we are looking at how do we coordinate our small footprint with the California footprint, with the regional footprint, to do this in a cost-effective manner, in as many ways and means as possible. The other thing the ISO is also looking at is some of the needs for -- it started as planning reserve margin, and so it is some of the needs around adequacy, and this, in our opinion, lends itself to some scenario planning as we look at overall adequacy. I think that was another point Pat was trying to make, is that you not only need to look within the pocket, you need to look at the system in total and make sure that, as you are moving things around, you have not inadvertently missed something. So it might be import capability, it might be load growth, it might be something that we have seen that we need to take the whole system into consideration. So I apologize, that is a very long way for me to say, "Yes, we are on it."

MR. HESTERS: No, no, actually it leads me to --

COMMISSIONER BOHN: Can I interrupt just for a second, before we pass this and in light of your comments? I would appreciate some guidance, and I do not know whether it is from you, or from the utilities, or from whom -- and this is the mechanic talking now, we are trying to figure out how we link all this stuff together to make it work -- how might we encourage the utilities to make the changes we are talking about? When we are talking about procurement, we need to have procurement take place before, presumably, you phase out some of these old plants; suppose the plant is phasing out, is in somebody else's hands, as opposed to the utility that we are permitting to build a new facility? How do we integrate the overall solution around the procurement process which perforce requires us to deal with dollars and cents and stuff that is supposed to happen? Is it from the ISO? Do the utilities have the responsibility of saying, "Here is the preferred solution and this is why?" Do they get their guidance from you? I am just trying to figure out how, mechanically, when somebody comes in and says, "We want to build a power plant and this is why," we link it somehow to the broader objective of this once-through cooling exercise when, perhaps -- and I suspect more than infrequently -- the mitigation of the once-through cooling is in somebody else's hands, and maybe somebody else's location -- how do we link those together in a meaningful process that is sensitive to the cost that we are again inflicting on the ratepayers?

MS. MANZ: I am going to suggest that this is a ripe area for discussion. I am going to suggest a few other things. I do not think it is the ISO that wants to be in charge of a procurement process for the IOUs, I am pretty sure about that. So I think we can use the basis that we have right now, where -- let me just take the existing local capacity requirement process -- where the ISO will do the technical studies, and then say, "In these particular areas, you need more procurement as opposed to other areas where you do not," and that informs your existing process. I think we can do all of this within the existing process. Another thought that came to mind as you were talking was to tie this back to the merchant non-merchant conversation we had earlier where, if you do have a power plant that really wants to just use the ISO market, which has sort of gotten its revamp and is pretty much on its feet now, that is a different level of intervention, I would suggest more lite handed, than if you are going through your IOU direct to rate paying customers process, and that you would want to have definitely more technical rigor, and talk LCR, the Local Capacity Requirement, and then what would those be based on once-through cooling.

COMMISSIONER BOHN: One question, therefore, if that is the -- I will not hold you to this, I am just trying to figure out --

MS. MANZ: My boss will not know.

COMMISSIONER BOHN: I will not hold him to it either. If that is the available information that the ISO provides and takes responsibility for, now my question to the utilities is, is that enough information for you to come in and ask for a mitigating solution to the once-through cooling problem for plants in your jurisdiction? Is there something else you need to know? Because part of our discussion is likely to be, because you are going to come in and say, "Well, we have this once-through cooling problem, but it is up in Tulare County," or somewhere, and I am trying to figure out, do you, based on what she said, do you now have enough information to make a meaningful argument that we at the PUC can actually evaluate? Or is there some other missing piece of information that we need?

MS. ARONS: Let me go back historically and tell you about how we used to handle reliability problems that we would find on the ISO controlled grid. We had a situation where, prior to deregulation, we could operate units according to what we felt the reliability needs of the grid were. And when we deregulated, we found that the units were not always operating that needed to be operating to manage reliability problems, and so they were given contracts under which they were obligated to operate, and they were given payments under those contracts that set, if you will, an economic target or threshold for which transmission had to be less expensive than, in order to justify that transmission project. The situation that we are faced with right now on once-through cooling is a little bit different in that, those units are moving towards shutting down, and we are looking at the economic cost of doing some sort of cooling replacement construction. But if they had to do that, in order to manage the reliability of the grid, then the cost of that construction, whether it is cooling towers, or what have you, becomes, if you will, a threshold cost for the alternative transmission that might be necessary to mitigate that shutdown, and that could be through displaced power in the impacts on loading on the grid, or it could be through having to refurbish or increase, if you will, or "restore" is a better word, your import capability. So there is a dynamic in trade-off that, in the past, we had through RMR contracts. I am not sure that we are going to have that vehicle to look at today. And so the question is, because transmission is such a long lead time, we would have to commit to a transmission project today in the event that a generator said to us that they are going to shut down in 10 years -- how do we really know that what we are going to be building is going to be used and useful if, for some reason, that generator decides to go ahead and do a repower and continue operations, which would naturally satisfy the grid? I think the problem is the generator has very short lead time decision making that it can make, while transmission investments are much longer lead time.

And it simply becomes a question, "Do you know with certainty these generators are going to shut down?" Then you have to put something in on the transmission grid to manage the reliability issue. You know, that is a simple commitment that you can make, but you do not really -- you know, the need issue that would have to be proven at the PUC to your acceptance is something that we would have to think about -- how do we know for sure what the future holds with respect to that generator, or group of generators. We just do not know.

MR. MANSOUR: Maybe Commissioner Bohn, maybe I can give you actual examples of what happened the last year or two, the specifics, and see, you know, the process we are talking about. The record is in place that, for new generation that is required for resource adequacy and reliability to ISO, took a position and recommended to the PUC and participated in hearing to support the needs of certain facilities that happened, for example, Edison, there were over five locations over the past couple years. There are also cases where, like Potrero, for example, Unit 3, where we said, "When the transmission goes into place, you can take it down, we do not believe that you can make the decision of taking what is in there out before the replacement is in." And that was the trust [inaudible] [35:11]. So that is the [inaudible], the one that comes in

2010, that Potrero [inaudible]. And there are other cases where also we said, you know, "Do you want to take something out before the solution is in," again, we took the position of saying, "No, you cannot take it out because [inaudible]. So in every one of those cases -- and there are some cases where there were proposals in front of the Commission where we really did not care where the location would be, it was not a location-specific, we did not come and say, "No, it is that location," we just said, "Well, [inaudible] that we would not take a position on where a location is going. So the ISO is being very over the last two years, I can give you many examples in front of the Commission where we did actually come and say, "Yes, this is needed." Or, "No, you cannot take it out," and then when it happened, it actually did," so it is through that same process, in spirit, that we will continue now as Ms. Manz said, it is the process of getting to that decision is getting complex, but you will still get from the ISO without taking the decision-making on natural [inaudible], you will see the ISO maintaining its role in actually supporting, for the record, what is needed and what you cannot do and what you can do from [inaudible].

COMMISSIONER BOHN: That is very hopeful. The question is, can you also order them to shut down to your point? That is to say, they say they are going to shut

down and you make a deal, and they decide they want to
repower, can you control that decision?
MR. MANSOUR: No, we do not order it down. For example, if the transmission -- let us say the transmission is in place and [inaudible], now, the need for existence would be something else. So [inaudible] [37:07] repower, it would not be [inaudible] just the [inaudible] its own, it could be for resource adequacy, the overall system-wide, it could be for [inaudible], it could be merchant, like Mr. Harris said, that I am going to take my chance. That would be a different justification, but it would not be anyway just a [inaudible] because we solved it in a different way.
MS. ARONS: If I could speak to that --
COMMISSIONER BOHN: So your issue, Pat, if I could answer the question -- your issue, then, sounds like you never will know, that is to say, whether the generators -- you come in and talk to us and say, "We are building this to deal with this plant that is being phased out," the plant -- you get to the time it is supposed to be phased out, it is not phased out, that situation cannot be solved.
MS. ARONS: Well, I want to speak to -- I think there are two problems that we are grappling with; the first is, we do not know the consequences, cost consequences, on the power grid from the shutdown of the once-through cooling from these new regulations. So nobody

really knows how big or how small those consequences are and we are all struggling with it. You are asking questions more along the line, we will assume that that is going to happen, you know, what are you going to do about it? And I cannot say that I know. I do not know what I am going to do about it because I do not know what is going to happen with those generators. There is no certainty around what the owners' decisions will be, and so what is appropriate to respond could be, well, we could on the one hand, in an extreme condition, be very cost conservative and say we do not want to do anything until we know with certainty. Or, we could say, well, you know, this thing is going to happen, we want to be very risk adverse, so we will build more than what we might actually need. So somewhere between the two ends of that scale is the reality where we would land, and I cannot say for sure what that would be right now because I just do not know.

MS. MANZ: I would like to try a little scenario with this to say, let's assume we did get an LCR designation, you did the procurement directive, it was completed. I think I am hearing your question, "How do we know that old stuff would go away?" And what would happen in our process is that we would no longer designate specific units as RMR, which is how they get their fixed cost recovery. And so that fixed cost recovery would go away. We have an economic security constraint dispatch, which means we try to take a least cost, most efficient, to operate. And so, if you have no potential to recovery fixed costs, you are not called in the dispatch to run, you have no revenue stream any longer, and I think that would be a scenario leading to plant closure over time.

MR. MANSOUR: Unless they find something else, and that is what I am saying.

MR. HESTERS: Or unless they repower --

MS. MANZ: Right.

MR. HESTERS: -- but they are also required to make other investments if they do not repower or replace.

MR. ESGUERRA: So, to Mark, in saying that -- just ask another question -- so would this be something we want to consider revising ISO planning criteria to put language in there, to be more -- I think that is the direction we are going in, but do we want to look at that and say, "Well, you should plan for minimizing OTC," and be very proscriptive on locations?

MS. MANZ: I think we have the ability to do that already in the Order 890 process, that is where we have a whole big stakeholder process around what should go into the planning assumptions, and what should go into the scenario analysis, so I do not think we need a tariff change. I think we need just more voices in the room.

MR. ESGUERRA: Well, it is more codifying in the planning criteria document.

MS. MANZ: Which is done every year, yeah, that is part of the process.

MR. MANSOUR: And remember, as we said earlier, this is something you do not need locally, but you may need it for those [inaudible] [41:00].

MS. MANZ: Right.

MR. MANSOUR: Now, you may still need to solve the local problem, but if they stay, they have a contract in terms of adequacy, system-wide, with the utilities, not for local, as would be not ISO, but the utility part.

MR. HESTERS: Mo, I am going to get to you, but there is a sort of follow-on to this, which was question three. We got the LCR study, we have got the ISO planning process, one of which identifies capacity, the other which could be identifying transmission needs, which we then take -- we guess years to permit, as Pat has been saying, 10 years is sort of minimum. The energy agency proposal talks about rolling the once-through cooling rule into the 2011 ISO Transmission Plan; that essentially means it is studied throughout 2010 and goes before the ISO Board in 2011. If there are transmission solutions that are identified and in that process, is that soon enough? Or is something more needed? That was for Pat. Mo is going to come next.

MS. ARONS: You are asking me that question? I do not know. I think it is an interesting question. I do not really have an answer for you.

MR. HESTERS: Mark, do you have anything on that?

MR. ESGUERRA: I will let Mo take a stab.

MR. HESTERS: Well, actually, Mo is going to roll back into 1, 2, and 3, and how LADWP does this and works with the California Transmission Planning Group.

MR. ESGUERRA: Is there enough time -- well, for PG&E, because looking at our system and for a specific location in our area, I think it is not that big a deal for us because we have identified monies and know the forms, but I cannot speak for the other utilities on what type of transmission would be needed. Depending on the timing of when the shutdowns are going to take place and the time it takes to build large scale transmission, it is hard to say. I would probably say I would err more on the caution that it might not be enough -- enough time, but it is hard to say. It is tough to answer.

MR. HESTERS: Laura, did you want to weigh in on that?

MS. MANZ: Well, I think we have some answers in going through the Renewable Energy Transmission Initiative. We solved a similar kind of problem to say, how is it that we are going to identify competitive renewable energy zones, how are we going to come up with a conceptual transmission plan, and what did it take us -- about 18 months to two years, I would say. You know, and so --

MR. HESTERS: At least.

MS. MANZ: Well, and there is a lot of new things that happened there. I mean, it was the first time we worked together as the State, with all of the people, with a voice and something to say to come out with a solution on the other end. So I do think there was a learning process in all of that. I think we have at least a semblance of what I would call a conceptual transmission plan, and then the question is, how do we take it from paper, I mean, yes, we can do this as part of the regular ISO planning process, but then how do we turn it into stuff? And that is the part that I think we are still kind of working on. And to go back to something Yakout said, you know, there is every possibility and potential to, you know, hold at least in time until you get that transmission in, the plants that are there. So this sort of glide path out, I think, we can continue to push on all fronts until we have a good sort of longer term reliability plan.

MR. HESTERS: Okay, Mo, now it is your turn. And mostly, the energy agency proposal runs through sort of ISO and not LADWP specific, in which case -- the Los Angeles Department of Water and Power -- I would like you to address it more from how the Los Angeles Department of Water and Power is dealing with it, and when we get to five, we will discuss sort of how the California Transmission Planning Group could be used to work on some other solutions.

MR. BESHIR: Thank you, Mark.

COMMISSIONER BYRON: Mr. Beshir, if I may, I would like to welcome you. You have been waiting very patiently all day, and here we finally get to you towards the end of the last panel, and if I could just use Ms. Manz's comments earlier about what a happy day it will be when the entire transmission planning process is all under one hat, I suspect you might not feel the same way, nor would you necessarily want to be part of this complicated procurement process that we have been discussing a lot. So we look forward to your perspective as to what LADWP is doing.

MR. BESHIR: Thank you for the opportunity. Definitely, I was kind of confused for a while on all these acronyms and processes, but on a serious note, in general, we do have the same concerns, the same issues. I mean, this is really -- we all live in the same area and the same neighborhood, so we do have the same issues with the generation concern we have, with the environmental issues, as well as the transmission considerations which go along with solving some of these issues. I think this is the same kind of issue. Number one, of course, the documents and some of the write-up here does not really address the issue of how we solve or how we look into this process from LADWP or from other municipalities, or public power, which deal with similar issues. LADWP does have three major power plants which are in the coastal area where we have had issues of a similar nature, we are trying to solve. We have, I guess, repowering programs we have been working on for quite some time, which we have done one phase of one of the plants, we have two or three phases we need to address and we would like to do. One area, of course, is for us a good Commission consideration, is really repowering. We are not really looking at replacement of those generation with some non-coastal plant at this time, so it is very important for us to phase in the process in a more tight fashion because we cannot really take whole [inaudible] [47:55] of plants to repower and come back in two or three years for the resource. So we do have a meticulous planning process on how we would like to do a repowering. So that is one of the considerations we have. One of the things we have done, we do continuously, is we have integrated resource planning process for LADWP, where we do look at all the issues associated with resource needs on an ongoing basis. We have very aggressive renewable protocol standard problem. We also have pretty aggressive greenhouse gas issues, mitigation problem, ongoing. So we do look at all of that in a very holistic fashion and try to solve all the issues as we go and in a comprehensive way, so it is very important and we do have integrative resource planning process where we do look at all the issues at the same time. On top of that, we do have transmission planning processes which we look at our transmission issues and try to meet our overall system in a more reliable fashion. Furthermore, we are engaged in the RETI process, as well as the efforts for the California Transmission Planning Group. We have -- I believe it is going to be a necessary component in solving this and many other issues the state faces, the greenhouse gas issue, as well as the transmission issues we have on an ongoing basis, including the ocean cooling scenario. We are talking about needs, a comprehensive look, by all of the California parties. As part of the California Transmission Planning Group, which has been set up to do many studies, some of the key components we see, and has been addressed in what we call our Work Plan, is of course the number one issue we are looking at, the renewable transmission development and meeting the 33 percent, or, for some of us, it could be maybe higher than 33 percent renewables, by 2020. But also, in the mix, we are putting the ocean once-through cooling issue as part of our Work Plan to look forward and try to solve and come up with a transmission component, or a plan to comprehensively solve that issue from all California perspective. In addition to that, of course, we have the AB 32 and many issues in that Work Plan, and as we speak, the California Transmission Planning Group is going to be having a stakeholders meeting on August 11th in San Francisco, where we are going to be talking about how to roll out a study plan to address number one right now, of course, is to do the RETI follow-up and look at the transmission components, and how to solve the renewable transmission issue. But, of course, we would also look at this as a component of the program and how to resolve these issues. So I guess, from your number one and number two questions, number one, I think to address our issue, the documents need to maybe address some of our unique considerations from that perspective. You had a question, I guess, about transmission issues and how long it does require to build the transmission. As part of solving some of our ocean cooling issue for our SACCWIS, we are looking at some additional transmission components, which will is essentially upgrading and enhancing our underground transmission, and that is in the works. It has been in the works for three years now, and hopefully in the next couple of years we will develop that and it will give us a little more room to maneuver and help us with some of that issue. Another thing we have at SACCWIS, which is unique also is, that is a kind of [inaudible] [52:09], it has consideration not only from the reliability, but also from the renewables where we are taking a digestive gas and burn that in the boiler, so that has to be a 24/7 operation in order to take this renewable component. So we are putting in a separate unit support of that component, so that is going to help us move forward from that perspective.

MR. HESTERS: Thank you. I was going to run to question four, we have had some sort of answers to this and it is pretty complicated, again. Assuming we have got the studies done by the sort of start of 2011, the next step, assuming that the studies identified some transmission solutions or alternatives to once-through cooling, would be approval and permitting an approval of those projects. Would we need changes to existing permitting and approval processes to facilitate these projects and get them moving in accordance with the sort of aggressive schedule that the Water Board has set forward? And if we do need changes, are those changes something that can be made within an organization? Do they require stakeholder processes? Would they require a tariff modification for the ISO, or are they essentially legislative actions? And some of these obviously are longer than others. But, again, we have got an aggressive schedule set forth by the Water Board. If we assume we are going to meet that, are there things that need to be done to the approval and permitting process for transmission?

MS. MANZ: I can speak all the way to the point of approval, I do not think I can go into the state's permitting. So let me try that part. We have a process that is already a FERC approved process, that we look at what the transmission solutions would be, and then we have a step that says all other comers can put their solutions into what we call the open window. And then there is a step that says and we assess to find the fit that is best. And that is a transparent stakeholder driven sort of platform, so I think we have the tariff language, I think we have that process. And part of the findings in that would inform the local capacity requirement, procurement obligations, or findings. So I am not sure that answers all of it, but in looking at the scenarios that we would want to do in once-through cooling, to sort of say this is in our planning assumptions, that we are going to find a way to mitigate that.

MR. HESTER: So this is just to run through years.

MS. MANZ: Uh huh.

MR. HESTER: Does the study in the 2011 process, or ISO plan, so that would be adopted by the ISO Board --

MS. MANZ: In 2012, yeah.

MR. HESTER: -- well, early 2011, so it is study that would be done next year and adopted in 2011.

MS. MANZ: Right, uh huh.

MR. HESTER: The open window solutions would then come by October of 2011, sort of the alternative solutions?

MS. MANZ: If you are studying it in 2010, the open window is at the end of 2010 because the final plan submitted to the Board would include those.

MR. HESTER: Okay, so that would mean --

MS. MANZ: So those would be included in the 2011 submission.

MR. HESTER: So then you could have a comparison done by the end of -- assuming you could get it done.

MS. MANZ: 2010.

MR. HESTER: Yeah, in time for the 2011 -- okay.

MS. ARONS: Well, I will jump in again. I come back to the question that, let's suppose we knew with certainty that the consequences of shutting down all once-through cooling generation in California required three new 500 Kv lines, and we had that project scoped out, and we had good cost estimates, the question that we still face is, until we know the fate of the decision of those generators, whether or not they are going to shut down with certainty, we cannot prove need in a licensing process.

And I am not sure if the ISO would even agree to approve need unless we knew for sure that those units were going to be shut down. From a utility and investor perspective, I think we would still -- if we were, for some reason, ordered to go forward, I think we would have to have an understanding upfront that we are doing so, not because we know the fate, and know the absolute need of these three lines, but because the state has made a policy decision that requires these facilities to be done, and therefore the need is, in effect, decided up front, if we can get assured rate recovery and 100 percent abandoned plan, if we can mitigate those regulatory risks from the utility investor perspective, I think that that would go a long way to making sure that things get done. But, you know, the situation that we are in, or the way the world works today, is that when we go for a CPCN application, for example, we have to know that there is a need that is demonstrable and, if it is tied to a generator whose owner has not decided what they are going to do yet, you cannot really prove that. So can you really get the CPCN? Can you even potentially go out and condemn and take property to accomplish those new 500 kV lines if you do not know the fate of those generators? So I think there are some real policy considerations that we have to think carefully about.

DR. JASKE: Ms. Arons, let me ask you to answer that question again in light of Mr. Bishop. Mr. Bishop says no Southern California OTC plant will be permitted to operate beyond 2020. Would you answer your question in another way?

MS. ARONS: Well, if it is an absolute certainty and we knew that these three lines were needed, and we knew that we could get a CPCN, that the need was in effect through that regulation proven, to the extent that, you know, where we felt that we could prevail in, say, a court of condemnation, if we had to take property in order to accomplish that line, I think that those policy pieces have to be absolute for us as a utility to go forward and build new transmission. I mean, we can look at 2020, but how do we know that those units are not going to repower in 2019? Because market conditions, for example, are very lucrative, and it makes the repower opportunity look like a very good deal for that plant. That is the problem that I am faced with. I do not know if they are going to shut down or if they are going to repower. And if they repower, there is no reliability need. Well, is the PUC going to give us a permit to build a 500 Kv line that may potentially require a condemnation, and come to find out in a court of condemnation that there is no real need; the need was on the theory that the generation was going to shut down, not on the actuality. And that is the problem.

MS. MANZ: If I answered the question that was asked, if we knew this had to be gone in 2020, right? We would do the planning that said it needs to be gone in 2020, and so that is the case that you would have, and then you would look at, all right, maybe the solution is three 500 Kv lines, and then that is the solution against which we would do an offering, or a procurement, or offer other solutions to come in, maybe we could find something more cost beneficial that looks like power plants for three 500 kV lines, and then that is, I think, what we would be moving forward with. So I am --

MR. HESTERS: Well, I guess --

MS. MANZ: I mean, I am happy to have more conversations around how this would work, but I am hearing more uncertainty presented than I am hearing in the question asked, that some of these are really points that are nailed down. And so either the power would be repowered and available, or they would not be repowered and available and we were working on the transmission solution, in which case I think we would be -- and we were 10 years out in front of it, nine years, eight years, whatever, but we are still a little bit out in front of it. I think we would be also looking to what else we could do from a demand side perspective, we would be looking at other solutions to make sure that when, you know, hammer comes down in 2020, we are ready to do that.

MR. HESTERS: I guess what, I mean, it comes down to is you are looking at an L.A. Basin that is densely populated, hard to build transmission power plants, I mean, transmission lines tend to affect a lot more people. So 10 years is probably a pretty reasonable time frame to at least get started on the planning, routing, that kind of thing, even if you were not getting to actual construction and everything else. So, I mean, one possible policy change is something that allows you -- that says, because of the once-through cooling uncertainty, and we do not know whether or not we can build generation into the basin because of air quality, or air permits, that you are allowed to recover planning and routing costs, but sort of delay making a construction decision as long as you can. I mean, is that -- does that sound like a change in regulation, or a change in current practices, that would facilitate adhering to meeting the once-through policy goals?

MS. AHRENS: Well, again, I mean, I have not been told that there is certainty that these units are not going to be there. I mean, I am being told there is the possibility that they can be there, and that casts uncertainty in my mind as to whether or not you can prove your need in the way that you have to, to be able to get ISO Board approval, PUC CPCN's, and be able to prevail in a condemnation. So delaying decisions on new investments is just delaying that decision. You know with absolute certainty, you know -- how soon will the future get here, and what will the future hold are questions I cannot answer, but I can tell you that, you know, there is going to be a lot of transmission that will have to be done, it is going to be replacing potentially two 30 Kv facilities with 500 kV facilities, and potentially developed, congested areas with many new homes, and there is going to be big consequences and challenges of doing that kind of transmission. And I think that when you put the decision from a policy perspective to be risk adverse on reliability, you are really moving forward and potentially having to put in place some very big facilities on the theory that something might happen is somewhat difficult.

MR. HESTERS: My only problem with that is, almost all of transmission decisions are made under those kind of uncertainties. I mean, Devers/Palo Verde II is, you know, cost effective only if certain amounts of generation develop in Arizona. Sunrise has the same sort of issues. We spend a lot of time arguing over what the price of gas is and whether renewables are going to be developed. This is just another one of those uncertainties, but we actually have a state policy in front of us.

MS. ARONS: No, this is very different. I would not agree with you there. The renewable generation that we identified and worked with in RETI is largely in unpopulated areas, and the issues that we are going to be faced with on dealing with once-through cooling shutdown are going to be in very very populated areas, and there are going to be some very big impacts that are going to be very challenging. And there is going to be lots of public opposition and lots of legal challenge, and so we have to be able to move forward with a lot of certainty if you are going to prevail potentially in court with putting, say, a 500 kV line in the L.A. Basin. It is not going to be an easy proposition for us. Maybe LADWP has a different point of view.

MR. BESHIR: Well, I think in general I do support what Pat is saying because I think we do have similar kinds of issues with transmission in the Basin, not only transmission in the Basin, but we have tested transmission even from the renewables, which we thought was easy, but it is not easy, even from renewables. So I really -- one thing I say is, if it is a definite scenario, now we are talking about -- not a scenario, but it is a definite policy that the resources are not going to be there by a date certain, then you really have to plan for it and try to find a way to do that, and I think it is probably a very expensive proposition. You are talking about -- it may not be overhead transmission, but you may have to come up with some very underground transmission, a very expensive proposition, you know, to do that. And as the investment becomes larger and larger, I think the certainty has to be bigger, higher to spend that much money. And that is really where the issue comes. But as of now, I think our main issue from the ocean cooling, or from that perspective, we are not really looking at shutting down any of our generation. I think all our transmission is built around this generation, the ocean cooled generations we have. It would be a measured restructuring and redoing of our transmission system if we were able to shut down those generation plants. So the whole concept we are talking about, we are trying to find out a right way and with the right time frame, and the time line has to allow for things just to happen for repowering because a good number of them are old units, they have to repower, we just have to repower them with the right technology, but there has to be time allowed to be able to do that in a timely fashion.

MR. HESTERS: Well, and also, as we heard, some of those plants have very limited space for repowering or for some other alternative cooling.

MR. BESHIR: That is correct, as well. Yes.

MR. HESTERS: Mark, anything?

MR. ESGUERRA: Nothing else to add other than I do support what LADWP and SE is saying on cost recovery and certainty.

MS. MANZ: I would like to speak to the issue of cost recovery. I really cannot talk too much about development. I am sure it is going to be complicated and sort of protracted at some point, but as far as our process, there is TAC recovery based on a determination of need from the ISO's planning process. And so, if this is sort of a thing that we are working toward, our planning process would then support this, and it would go in front of the Board within sort of that first cycle under our determination of need. Once the Board approves it, it would go into the TAC, or the tariff for cost recovery. So I do not know if that makes anyone feel better, but there is a way through in our process that I can think of.

MR. HESTERS: I guess we are pretty close. We do have the final question, which has to do with whether or not increased interconnection between essentially Los Angeles Department of Water and Power and Southern California Edison, should be investigated as a solution to this once-through cooling power plant retirement problem, given the sort of constraints of new generation in the area, mostly with regards to air permits.

MS. ARONS: Yes, that and more. I think we do not know the full scope of what the consequences of this regulation is going to be in terms of the impact on the grid. It can be, you know, you are shutting down potential large inertia contributors to the stability of the grid, it is going to require a lot of different kinds of solutions, potentially, to be developed, and it is going to be more than just interconnections between utilities, it is going to be voltage support, it is going to be some kind of large maybe even disbursed static bar compensators to provide voltage support in places where we need it, it is going to be a lot of different things. And a lot of work has to be done to even scope out what those elements are. But it is very far reaching and I think Mo said something very quickly that is worth remembering here, and that is our systems have grown up around these generators being in place, and you are talking about a really foundational element being removed, and having to restructure your entire grid is going to be a very big challenging activity for the engineers of the future.

MR. HESTERS: Laura, anything?

MS. MANZ: Nothing more to add.

MR. BESHIR: Yeah, I just wanted to maybe echo what was said, but in addition to that, the way the system works in that part of Southern California, of course, is we do have, in terms of generation or local generation, but we also have generation outside the Basin, which we import. And it is a pretty known fact, the import capability of the transmission in the resource we have depends on the generation we have in the Basin; so the larger the generation we have, the more we can import, ironically. So we can extend that to say it takes a good number, which could be about 30 percent of the resources we are talking about in the Basin, out of the equation, you really need to do some creative ways to bring that power home from our side. And I think that is really what the challenge is. And it could be cost-wise very expensive, but most importantly, I think it does, I guess, underscore the need for planning, the need of coordinated planning, between all the parties involved, because it does require maybe integrating our system a little bit differently than what we have done before.

MR. HESTERS: Any questions, not that there are not many throughout.

COMMISSIONER BYRON: Gentlemen? Mr. Mansour, this is all for the benefit of the ISO.

MR. MANSOUR: We appreciate it. Well, let me just again, not just this time, but through the day, because actually, just correct me if I am wrong, which as a conclusion I would kind of at least, as a state, feel that we are comfortable with it. Repowering or doing something where things are compared to spending it in the air is really without, you know, you can do it in the back of an envelope, or you can do it in a two-year study; it looks like everybody is saying, you know, focus on where it is. If it is, it is going to be faster, it is going to be more efficient, it is going to be more certain, all the issues you are talking about, and that takes us to, if we were to focus on the local one, then try to really encourage that by the procurement process and all the rest of it. Whether this panel or the rest, do you agree with that observation, at least from sitting there? Anyone?

MR. BESHIR: I will go first this time. I do agree. I think the most efficient way from my perspective and the most straightforward solution is really if can re-power, I mean, I think that is the way to go -- how we repower and whether to meet the environmental need, I think that is really going to be the challenge with space issues and some community concerns we have, and that also saves the timing requirement because now we can at least shut down a whole plant, to depower it for four or five years, because that kind of defeats the purpose right there because you do not have the reliability requirements for those years, so you can at least survive. So that really extends the time required to do this in a more meticulous and more systematic way.

MR. MANSOUR: Pat, do you come to the same conclusion?

MS. ARONS: Well, I think, you know, given that we do not know as much as we do not know about the impacts, I think repowering is a very sensible approach to take. You know, with a lot of renewables, solar, wind, they do not have inertia, they do not have large voltage of core capability, they are good energy producers, but you really need -- in a big power grid like this, you need a very large central generating plant, you need big inertia, you need massive voltage support, you need the kind of boost that you can get out of these units on a millisecond notice if you have a major event. And I think that, to move quickly into just a shutdown scenario, I think is a big mistake. I do not think that we really understand or appreciate the value that those units, that they have, even with the future of 33 percent renewable, I think those units are very valuable contributors. I think we would make a mistake if we rush into regulation that is going to drive them out of business too quickly. So I think this is a decision that, whoever is doing the regulation, needs to be very thoughtful, take into consideration what those costs can be. I think they are going to be enormous, both dollar-wise, as well as reliability-wise.

MR. MANSOUR: So the proposal from, you know, the joint proposals from the three of us, which says, you know, focus on what is possible, technical reliabilities above all, do the cost analyses, and review every two years or so regularly the progress on both sides -- is the Water Board achieving its goals through the joint process, or if it is not going, then look at the schedule again. Do you have anything to add to that position? Is that appropriate? I just want to make sure that the three of us -- is there anything that we are hearing by which we need to change what we are supporting, or what we issue in support of this particular ruling?

MR. BESHIR: One area I do see, I guess, is I think that is very sensible, I think it is systematic for number one, it does have a feedback process, and it does have, I think, a thoughtful process going forward to achieve what we have. But what I see in Appendix B, though, the timeline seems very aggressive. And I think one of the things we have talked about a lot here, and there is already some timeline or anticipated timeline where this thing is going to occur, and that may really be short or may not really meet our expectations, and we really need to make sure that thoughtful process really has the appropriate time to go along with that.

MR. MANSOUR: But the fact that we are saying we will visit regularly, every two years, whatever it is, to see really whether things are happening on the timeline, is it too fast, or -- does that give you the comfort?

MR. BESHIR: Yeah, definitely. I think that is a very thoughtful process. I think it does have to have a feedback process that is very well designed for feedback process, but we are just talking about a process at this point, we have not really seen, you know, what kind of mechanisms, how well the control is, what does that mean, and the different pieces we are talking about right now, for instance, the repowering we would like to do in Southern California, we do really need to have AQMD issues resolved so that we can have the right permits, so that we can start going -- we have some repowering in our books which really need to get going so that we can meet some of those issues. So all these things really need to work together to be able to meet our goals. But definitely, the process is appropriate.

COMMISSIONER BOHN: May I just -- as a layman, I -- the repowering option, as a non-technical person, strikes me as almost too easy. You have got a box, you have got it connected to stuff, you pull out one thing, you stick in something else. Okay. From a policy point of view, as Yakout says, you can do that calculation probably on the back of an envelope. I guess my question is, is that alternative -- does it have the same degree of longevity and flexibility that the system will need 15-25 years from now? In other words, if we solve the once-through cooling problem, have we solved enough of the problems that confront the system, such that we can say we have, in fact, modernized the system to be competitive at a reasonable cost? Or are we condemning ourselves to use -- or favor -- either technology solutions or locational solutions which, over a longer period of time, or a broader perspective, might be better suited to the year 2025? I do not know the answer to that, but I would appreciate some guidance on that.

MS. ARONS: I think that, if you have to make the decision using one characteristic of these existing units as your guidance on what the future may be in terms of the adequacy of new technology, I would use the inertia factor on the generator. The fact that you have large, heavy rotating mass spinning at about 3600 revolutions per minute, provides a lot of electric stability to the grid. So if you have a 1,000 Megawatt generator, it is going to have a very big heavy shaft spinning at a very large speed, and it is going to tend to want to stay at that speed through disturbances on a grid. If you were to remove that single unit and replace it with one-thousand, 1-Megawatt unit, spread around the grid, you would lose a large amount of inertia and your system would be negatively affected by that. So if you were to make your decision using one guiding factor, that would be my recommendation, to look at and judge every replacement technology, every replacement generator, in terms of not Megawatts that they produce, but the inertia that they bring to the system. You might need 3,000 Megawatts of combined cycle units spread around the grid to be able to shut down that 1,000 Megawatt generator. So, to me, that might be the measure of impact on the grid; instead of counting Megawatts, count inertia.

COMMISSIONER BYRON: I think we -- in the interest of time, we need to move on. I would like to thank you all very much for being here. We are going to go to public comment. You are welcome to continue in your seats or go back into the audience, and I am going to proceed right into public comment.

Agenda Item 8: Public Comment

COMMISSIONER BYRON: Ms. Korosec, I only have one blue card, but that does not limit the rest of anyone else that wishes to speak. But I will go ahead with this one first. Mr. Krausse from PG&E.

MR. KRAUSSE: Thank you. And I can be very very brief because I know it has been a long day. Mark Krausse with Pacific Gas and Electric, mostly to say thank you all very much. We have been involved with most of the folks sitting in the audience here on once-through cooling for the last three years on what feels like maybe a pogo stick, entirely dedicated to eliminating the use of once-through cooling. And it feels like, with the inclusion of the energy agencies, we are very encouraged, it feels like we have got a couple of new legs for a three-legged stool, one of those is reliability, and one of those, Commissioner Bohn has driven home a couple times today, is customer rate impacts. We are very encouraged to see that this plan sort of integrates so much of what we have been saying at the Water Board for several years now. And Jonathan Bishop was here, I have to say, until right up until the end. I was pleased that he heard an awful lot of this. I know that he is kind of one of the authors at the Water Board staff, so I think that shows up in the current draft, and we are very encouraged by some of the changes in the most recent draft. But I want to just point out a few things that we think still need some changes, and obviously we will feed this into the Water Board's process. First of all, on the question of schedule compliance and whether there should be any adjustments to the current schedule that your staff has identified in this implementation plan, I think only the energy agencies should be consulted on that, the Water Board should look to you and you only. The current SACCWIS, the acronym for the -- I am sorry, we are in an acronym-free zone, but I have not memorized that one yet, what exactly it stands for, Statewide -- it involves the energy agencies plus the State Lands Commission, the Coastal Commission, several other permitting agencies that rightly are involved in parts of this process. But I think, on grid reliability issues and that schedule, that should be up only to your agencies in terms of the Water Board consulting you and you only. Secondly, on the nuclear studies, to determine for cost benefit purposes, sort of the cost side and the feasibility on the studies, Pacific Gas and Electric and Southern California Edison have done, and PG&E has already completed, a very detailed study to establish what the engineering challenges are, what the costs are of retrofit at SONGS -- on permitting at Diablo Canyon -- you will be pleased to know, we have got it all figured out -- Edison is underway with SONGS, the complete study of SONGS, and I think we would like to urge that the Water Board start from those studies and use your agencies as sort of peer review, as opposed to going out and conducting new studies. I think that is a pretty simple step. And then, finally, that being sort of the cost side of cost benefit, we would like to see more guidance given on the benefits side. And part of the reason, we have always been told, the utilities and the generators all along in this process, we need one statewide rule that all regional boards can apply, well, I would argue the same thing with regard to how cost benefits should be handled, so those regional boards should be given guidance in the regulation about how the benefits are to be calculated, and then also what the ratio of cost to benefits should be in order to be wholly disproportionate as that cost benefit variance provides for the two nuclear plants and the already repowered, or newer technology gas plants. And finally, on that same point, that some guidance as to mitigation costs -- once you have been determined to be wholly disproportionate on a cost benefit basis, what are the appropriate ranges of the mitigation costs? I think that would also be very helpful. But again, very encouraged by the addition of the energy agencies in this process, and thank you very much for all your work and your staff's work.

COMMISSIONER BYRON: Thank you, Mr. Krause. We have another public speaker coming forward, but before you begin, though --

MR. NELSON: I am sorry, I did not know we had blue cards.

COMMISSIONER BYRON: No, that is fine. Mr. Krause, I just wanted to address, you know, your points in another way. The notion of consulting only these state energy agencies, using existing studies as a starting point, and having one statewide rule, I just want to make sure that everybody understands, the energy agencies are not promulgating this rule.

MR. KRAUSSE: Absolutely.

COMMISSIONER BYRON: It is the State Water Resources Control Board that is promulgating it, and they are relying upon us for input, and to the extent that Commission decides these things, that is how it will be adopted. We cannot speak for that Commission. We do not know how they will proceed. And it is incumbent upon us, I believe, to demonstrate to the Board that we have this matter under control, if you will, that we will promulgate a plan that will meet their needs. So we are glad to have your comments, but I think you full well know, those comments and many of the comments we have heard here today, will be considered by the State Water Resources Control Board.

MR. KRAUSSE: Absolutely, and we will submit those last comments on the policy, I think "rely upon" were the words I was using, in other words, it is their discretion in the end whether that schedule slips or not, but I think they should rely on you -- the Coastal Commission and State Lands Commission, they have other data points to add, but not on grid reliability.

COMMISSIONER BYRON: Very good. I am sorry, please reintroduce yourself and welcome, again.

MR. NELSON: David Nelson with the Coastal Alliance on Plant Expansion. There are lots of comment on -- up to three panels, but I will make it as short as I can. One point I would like to make is, last year, 2008, the Country of Spain installed 2,500 Megawatts of solar power -- Spain. I mean, there are as many people in Spain as there is in California. Our gross product is way more than Spain's. So, you know, it is out there. And you know, I sat through this whole hearing today and I counted about 18 out of 23 people who were directly involved with fossil energy production, which is fine because that is what the backbone of our whole system has been up to now. But, if I could, the whole time I have been here, I have been admiring the calendar that is on the wall here, and may I just use a little pun -- "the handwriting is on the wall," look what these young people have put into these pictures. I mean, this is the future, and what we have got here is a lot of interest that have a lot invested in fossil fuel and making power the old-fashioned way. And what it is doing is stopping us from being the leader in the world, I believe, in the advancement of the solar industry. We talk about the South Basin and the air pollution problems down there. Here is the solution. We do not have to run these 500 kV lines. We do not have to do that. That is billions of dollars. What we need to do is, the PUC come up with some sort of a regulation all of these producers are asking for this and that and how to keep their businesses viable, I say let's get the PUC to give me a 10-year contract to put all the PV's that I can on my house at a set price. Right now, I have friends that have very expensive solar panels at their houses and I go, "Well, how much energy are you making? How much money are you making?" "Oh, well, I don't know. My bill is too crazy to even understand." So this is one of the big problems out there, that is stifling this industry, is that you are not allowing the homeowner or the person who is a big warehouse to put as many photo cells as they can -- and see a return. All these people are asking you for a return, they are all saying to go to the PUC and do this. I see a lot of our state resources and I have been on this for 10 years, and I really do understand how complicated this is, but I see a lot of our state resources going to try to understand this once-through cooling problem, and it is a problem, it has been shown to be a problem for a long time. But they do not want to let it go because there is a built-in benefit to it. I mean, when you are using once-through cooling to make your energy, you are making it cheaper than the guy that is making it away from the water, it is as simple as that. And then there is money to made in it, even at these crippled plants. But we are not taking into consideration global warming, and I certainly hope you all believe in global warming, and to put new power plants on the coast that is going to rise because you are making more pollution with gas does not make any sense at all. And, you know, I could go on, but, you know, just do not get just hung up on this one solution. I think the bigger solution, like I say, is all around you by the children of California, they are showing you we need a different way to do this. And this is not the only way, and it is not going to turn my lights out if you take a power plant off line. It is destroying fish stocks for the next who knows how long, and the damage that has already been done. When I first started this, there were energy producers up here claiming no damage to the environment at all, and regulators were taking that into consideration. Well, the damage has been proven, and it is huge. This should be an environmental disaster and every one of these power plants should be given a cease and desist order, and then prove that they have to keep running, to keep it running. That is the angle we should be coming at, not, "Gee whiz, we have always done this and your lights are going to go out if you take these power plants off." So take that into consideration. And like I say, a big thing is give consumers a reason to put these power panels on their houses. I guarantee if you put out an ROF for people to give up their houses to put solar panels on that you would get plenty of people that say, "Put it on my house, please." Thank you.

COMMISSIONER BYRON: Thank you. Do we have any other public comment?

MS. HAREN: Good afternoon. I am Angela Haren, Program Director for California Coastkeeper Alliance. Thank you for the opportunity to speak today. You have to forgive me because I am starting to lose my voice. Just really briefly, I wanted to note that we have heard a lot of comments today about the need for flexibility in the planning process, and we definitely acknowledge that phasing out once-through cooling is very complicated and it will take a dynamic review process, as you guys have proposed. But we also want to underscore the importance of enforceable deadlines for the State Water Board, and obviously they put some preliminary ones in their proposal. And I just wanted to note that, in terms of the agencies -- your three agencies -- working together to improve the planning and permitting coordination that Dr. Jaske referred to earlier this morning, is to keep in mind the goal of -- although it will be dynamic and there might need to be some review -- the goal of meeting enforceable deadlines for the State Water Board. And that is about it.

Thank you very much for this workshop, and we look forward to opportunities to comment further.

COMMISSIONER BYRON: Thank you, Ms. Haren. Is there anyone else that wishes to make public comment?

MS. KOROSEC: If there is no one in the room, I would like to suggest we open the WebEx lines. All right, the lines are open. Is there anyone online who has any comments? We have no comments online.

COMMISSIONER BYRON: Well, I would certainly like to thank our public commenters for getting us back on schedule. We do have -- the last item on our agenda is to talk about next steps and action items. I have not reviewed with staff how they would like to go about doing this, but the first bullet says Energy Agency Staff Summary of the Day's Discussion. Dr. Jaske?

Agenda Item 9: Next Steps and Action Items

DR. JASKE: Here I am in between everyone going on their way, so I will be brief. I have about five significant points I thought I heard, so I thought I would just run through them. Integrated Planning -- we heard some congratulations that the three agencies are getting together and proposing a process, but we also heard, particularly from Mr. White, a call for much tighter integrated planning going forward, and perhaps in the implementation of this process that we described.

Reliance upon preferred resources. Just by our attempts to say that what we are proposing here is that fossil plants not be replacing these OTC facilities, Megawatt for Megawatt, and that we are doing that because we are pursuing energy efficiency and renewables, and distributed generation, and other core resources, that message is apparently not fully getting through because a number of commenters seem to think that we should be pursuing all those things, as though we are not aware of that, and not planning on doing the best we can. So there is a communication gap, perhaps, between what we think we are doing and what the public things we are doing.

Licensing new thermal power plants -- I did not hear the panel really come to grips with the extent to which Energy Commission should do something different, despite a couple of questions that seemed pretty pointed about whether we should be modifying our processes, or whether air credits should be reserved for just power plants that are going to be replacements for OTC, I did not clear answers to that, so that seems either no one is just independently thinking about whether our process should change, or they just do not think it needs to.

Of course, there were a huge number of comments having to do with the timing of this whole OTC replacement process, and boy, if I was Mr. Bishop, I would be a little worried that he hitched himself to our star at this point because there are an awful lot of roadblocks being thrown up in the air about whether the timeline put forward in the staff paper, and that the Water Board staff has bought into in their proposal is viable. Many of those seemed to revolve around -- and I will just pick on Ms. Arons, you know, as the most outspoken person on these points -- about cost recovery of transmission projects, and the disparity between timelines of many many year transmission projects versus shorter generation projects, and the lack of, despite team and all the other things that ISO was doing over the years to try to be able to bring generation transmission into some sort of comparable process, that we are still not all the way there, yet. So that seems like a major issue, at least from the cost recovery side of things, that needs to be dealt with.

In contrast, I thought our two procurement panels seemed, by and large, to gather the details, but that the procurement process can adapt itself to deal with the challenge in front of them. Ms. Manz was pretty clear that the ISO's transmission planning process is perhaps broadened by this new stakeholder group that is just getting its act together, you know, is the right forum to examine transmission options. She did seem to suggest it might need some further tweaking as that process has been, you know, modified fairly continuously over the years to bring together the sort of massive set of resources that RETI brought together, both people and timeline and, you know, bring together a lot of detail. OTC might not be that complicated, but it certainly has major challenges.

I did not hear any person say today that the schedule that is Appendix B of the staff paper was too slow, that they had some means of going more quickly than that, with the possible exception of Rob Anderson, who, if San Diego's next procurement process, you know, manages to luck out, there could be a replacement for Encino identified and brought on line faster than what is in that schedule, I think that is the only possible place where what the joint staff put together could be improved upon. And we do not know that, that is just a possibility. But all of the other side of things was what was emphasized, that that is too aggressive, too fast. But as Mr. Mansour and one of our last panelists were engaging in dialogue, the whole point of the proposal and what the Water Board has accepted as this reopener's periodic update, is it allows us to correct that schedule as we learn more and more information, either from the first rounds of intensive analysis that we will do, or from the actual beginnings of procurement and transmission projects that are identified. So those are the major points that I heard today.

I think that in terms of some next steps, clearly we need to broaden the conversation from the energy agency staff and you folks who we had a number of discussions with, and the Water Board, to bring in the utilities, the transmission planning folks. When exactly we do that, and how we do that, that there is some working group process or some other mechanism, is not clear to me, but we will need to do that at some point to move to the next set of detail.

The LTTP process is proposing to be changed, to bring together a focus on OTC. It is written up in the energy division staff proposal already, they have a workshop, I believe it is next week, where that can be examined in conjunction with all the other many things that are proposed for LTTP. So there is a forum already for that side of things to be pursued.

And I think, lastly, we need some means by which the transmission planning process, particularly a broadening one that extends beyond the ISO balancing authority, you know, comes to grips with this problem, and how the regulatory agencies, the planning agencies, are part of that process, not just the stakeholders as the new stakeholder group has proposed. That is obviously an important effort that stakeholders come to grips, but the agencies need to be involved in some manner, as well.

So that is my summary of what I heard today and the immediate next steps. Do you have any questions?

COMMISSIONER BYRON: Dr. Jaske, thank you for that summary on the fly, and thank you very much to you and Dennis Peters at the Independent System Operator, and Robert Strauss, and all your staffs for the work that you have been doing thus far. We are only just beginning, really, and I see some heads nodding up and down, but that does not stop us from taking a breather and saying thank you. But I am sure my fellow dais members here have some closing comments that they will make with regard to next steps. Commissioner Bohn, Mr. Mansour, do either of you have some comments?

COMMISSIONER BOHN: Well, I just -- let me say from my perspective, this has been a most interesting and informative process. It is always interesting, again, as a non-expert in the field, to listen to the policy process at work. I want to thank, of course, our PUC staff, Simon Baker and Robert Strauss, who have been involved in this, and I will look forward to spending probably more time than you want with you guys over the next couple of weeks to try to sort through, sort of sort though some of these things. I think there are probably three points that I would make. The first is, I am even more convinced than I was when I started that this is a complex and interactive process.

And I think we need to be both cautious of our ability to get it done, and confident enough that somehow we will get it done. The mechanism, I think, is continued discussion and cooperation, as everybody has said. But I think we are a ways from the conceptual framework around which these various considerations can be weighed in the concrete forum of a procurement process. There is just a lot of stuff and we and others have to sort out whether OTC is more or less important than RPS and all of those kinds of decisions. I feel a little bit like we are a microcosm in this discussion of the current Federal Government dilemma in trying to do too much, too fast, and losing track of the process by which we order the priorities. So I think it incumbent upon all of us, and certainly at the PUC, and I expect we all feel similarly, to take enough time in the beginning of this process so that we do not waste a lot of time. There has been a lot of discussion, and I think much progress has been made in bringing reality into aspirational goals, I think the adjustment process that Yakout has outlined is a very good one. I am less concerned about getting the technical procurement process from the IOUs sorted out so that it is more efficient, perhaps than others. Once we have gotten some more guidance collectively as to the trajectory in which we are flying, and the pavement on which we are in fact riding, and water in which we are now swimming, all of these different dimensions, and the reason I mixed the metaphors is to try to highlight the different dimensions that we are talking about. And so I think that is an important factor.

The second brief comment I would make is that I think it is incumbent upon all of us to understand that we are at the edge of a major transformational process in the State of California. We are doing it in the face of a serious financial situation, nationally, at least as serious a financial situation in the state, and in the face of a mechanism which has shown itself often ill-equipped to deal with accommodation. So I think we are going to have to be a little more creative and a little more flexible among ourselves, and not worry so much about structure and not worry so much about who goes first, and if you want any kind of fuzzy logic approach, that is not a bad way to think about it.

And third, and finally, I want to thank Jeff and the Commission, and Yakout, and everybody spending so much time on this, and mostly for their patience in laboriously answering what, to them, are sort of simple and trivial questions, but for me, as a finance guy and sort of a policy person, new to this game, that they have all been very patient and very helpful, and I would extend that appreciation to the staff both up here and at the PUC for helping get me up to speed. Your patience is only exceeded by your good looks, Jeff.

COMMISSIONER BYRON: Thank you, Commissioner.

MR. MANSOUR: I echo my thanks to the Commission and you, Commissioner Byron, your leadership has been great in getting us together, as well.

COMMISSIONER BYRON: And what about the good looks, Mr. Mansour?

MR. MANSOUR: I was going to get to that on my closing comments. But, you know, in 2006, when we had the heatwave of 2006, and 2007, which was kind of a semi-heat-wave, the thing that probably most people should give attention to is, it is told, useable capacity in the State of California is about 54,000 or 50,000 Megawatts, counting everything. The peak load so far on record is close to 51,000 Megawatts, so when you talk about the capacity in California, compared to a peak load, even now, it is kind of 47, 46, you cannot stand on your own. We cannot stand on our own, period. So we are already importing about 25 percent of average of our needs from out of state. And those people are accepting that they maintain their plans, to actually give us that 25 percent or so. We do not have a lot of luxury within California in terms of, yeah, we can also take this and take this out, it is already slim. And also, during the 2006 heatwave, of 2007, and even during the crisis that I was watching from the outside, when we were kind of hanging by the teeth and we were asking people to raise temperature in the homes and all that stuff, we were on continuous scrutiny and questioning, why are we so tight? And at that time, I have not heard one voice that comes and says, "It is okay, what is the problem?" It is only when it is cool, like today, in a time when people say, "Why [inaudible] [112:04]?" But, you know, so can I please have your vote when there is something really tight, then you can actually tell people it is okay to lose power, and it is okay?" In fact, I faced kind of a hearing in the Legislature at that time, and people questioning, you know, the wisdom of asking people to raise their temperature to 78 and 80 degrees at that time, not cutting them off, but just that. So it is not like we have a luxury there that we can actually cut off, it is tight and with the fact that we are actually counting on 25 percent from out of state, the majority of it is in real time, on-the-spot, and it is not guaranteed forever, and for quantity, the state is cutting a lot more than usual.

Some people mentioned Spain. I will tell you, if you give me what is in Spain, I can rely on getting them to spinning wheels, and then I will be comfortable with it. Half of the capacity is reserve. Half of their installed capacity is reserve -- huge amount of reserve. It is not that they are putting all solar up and they are shutting the plants. If I have that amount of reserve in the state, that they are maintaining, I can tell you, you can do anything you want and I will come and tell you I can still maintain, you know, keep the lights on. You know, it is just like it is okay to sit around here in kind of in comfort, arguable of what is here and what is there, you know, why don't you do this, and the suggestion, it is not like we are not doing. In energy efficiency, we are talking about the state that, over the last 30 years, the average consumption per capita has been constant, compared to the rest of the country, you are talking about 30 percent or so, I mean, you can go on and on and on and the state has done incredibly better than any others. Now we are talking about really big issues, especially we did not talk a lot more today about, in particular, out of the volume that we are talking about, the crucial role of the new power plants. These are huge, this is big, this is big inertia, as Pat mentioned, and they are right in the whole center. Their issue is apart from even what it will take to do -- I am not saying going to do, or -- but it is something that you have to carefully, even within that volume, to have to look at very carefully about intent of how we handle during the [inaudible] [114:32] if it happens, or apart from the cost. So in total, we are not at all -- and our position with the agencies was never to question the wisdom of the policy, it is how to get there, and not just on its own, but in combination with everything else. The photovoltaic roofs, the sun does not -- we only start to pick up at 6:00 in the morning and goes to 1,500 Megawatts and 2,000 Megawatts per hour, the sun is not [inaudible] [115:11] force to give you what you want, and the wind actually is getting [inaudible] [115:16]. During the summer, the heat of the summer, the average outcome of the wind is on average about five percent of the [inaudible] capacity. So, you know, I could keep going on and on and on, what we are managing today and what we are accommodating, we never lose site of what we try to do as a policy, but we also know that the minute you start implementing those policies, and the lights go off, or things go crazy, then actually that will be counter-productive to the policies that you are trying to achieve, [inaudible]. And that is what we try to do, it is a balance, it is tough, and frankly, as one person, I am excited about it, I am taking it as a challenge, it has a lot of leadership, that if it is implemented, I would not even compare it to Spain, it would be way ahead of anyone that can do all of those things, it can do -- anyplace that can do all of those things combined. Again, thank you very much for your effort, the Commission, the staff, and all the comments that we have heard today, and the panelists.

COMMISSIONER BYRON: Thank you. Excellent comments. I will be brief. I think I will pick up where Commissioner Bohn started, as well. Commissioner, this is not easy, this is not an easy issue to wrap our arms around. Something I said earlier, if you think you understand this issue, you probably do not. It is extremely complicated. I started jotting down, you know, the physical constraints, the contractual issues, the how to deal with the cost distribution issue that you bring up, there are jurisdictional aspects, not all under single control here. The safety issues associated with it with the nuclear plants, reliability, the competitive environment that we are trying to retain in the State, as well, and, of course, the goal of all of this is environmental mitigation. These are difficult constraints to figure out how to put together. And there will be a lot of analysis involved, and I suspect a lot of it will not be on the back of an envelope. And we know that our Independent System Operator is going to get stuck with some of that, and there is a little bit of resistance there, because once you do one analysis, everybody wants to look at 17 analyses, and the parametric sensitivities associated with it, so we are very sensitive to that and it is going to be expensive, the cost associated with figuring this out in this economic environment is going to be challenging, as well. And then maybe a comment that Mr. Mansour made with regard to the approach the agencies are taking, and I was a little bit concerned with some of the comments I heard from some of our panel members. Some folks, whether they admit it or not, still seem to be fighting the need for mitigating once-through cooling. That train has left the station. A rule is going to be promulgated by the State Water Resource Control Board, and we must address it, it is not a question of if and there is not uncertainty around some dates that they have put forward at this point. And having met with members of the State Water Resources Control Board, I can tell you, they take their responsibility to promulgate a rule very seriously, they will move forward with a rule this year, and they must be convinced that the three agencies have a plan that will meet their needs, and I am talking about a reliability-based plan.

And another comment that came up that I cannot help but address, this concern about shareholders and whether or not they are going to be made whole throughout this process. Thank goodness there is at least one commission here in the state that is worried about cost and to ratepayers, and making sure shareholders of the investor-owned utilities are kept whole. But we need to meet the

Resource Control Board's needs now and worry about the shareholder aspects later.

There is a lot of emphasis, well, on the IOUs and jurisdiction of the Public Utilities Commission and the ISO's jurisdiction of all the IOU service territories, around procurement -- remember, that is not the full state solution, we have other participants in this process, the publicly owned utilities and the Muni's have an important role going forward, as well, and we need a statewide solution that addresses once-through cooling with all the load serving entities considered.

So that means we need all the stakeholders' participation, some of them I have not even mentioned yet, but you have heard from some of them today, and those being the environmental community, those that are concerned about ratepayers, there is a lot of participation that is needed going forward. This will not be the last workshop, I suspect, that we conduct on this subject. I think it merits a little bit more consideration, too, Commission Bohn brought it up, with regard to the financial impact. You know, we just do not discuss this much, we now apparently have a state budget going forward, but, really, the structural issues associated with our financial crisis in the state were not addressed in any substantial way. Most agencies in the state will be experiencing furloughs and that will have an effect on how quickly we can address this and a myriad of issues that are before us.

Finally, of course, this -- we are only really dealing with energy policy here, that has been the focus of our workshop, we are not really dealing yet with the cost impact of all of this, and Commissioner Bohn is right to bring that up with regard to ratepayers, and I am sure that the municipal publicly-owned utilities are concerned, as well. That is why I am so glad that he was here today, to hear all this, and the reliability aspect of all this continues to be extremely important, and I know that is why Mr. Mansour is here, because he is very concerned about it. I think the Energy Commission has an important role going forward because we bring the statewide perspective with regard to policy setting through our Integrated Energy Policy Report, and jurisdictionally for all the entities in the state. Having said all that, I believe that, in fact, we could not get enough at lunchtime, so the three of us sat and talked about this issue even more. I believe that the three energy agencies, going forward, are very committed to providing the State Water Resources Control Board what it needs to promulgate their rule, and I certainly welcome -- probably more stronger than that, I plead for your continued involvement in this issue because they will be the ones that will be looking to us to solve this problem from a reliability-based approach.

As far as the Integrated Energy Policy Report goes, which was the purpose of today's workshop, you have given us a great deal of input, we will be able to draw some meaningful conclusions and recommendations with regard to policy going forward. I certainly appreciate the commitment of the other energy agencies, the Public Utilities Commission, and the ISO here today, and I would like to thank you all for being here and sitting through one of the longer workshops, I think, than we have ever had. We will be adjourned.

(Whereupon, the workshop was adjourned at 5:33 p.m.)